ELECTRIC POWER IN CANADA 1992

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Electric Power in Canada 1992

Electricity Branch
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A Message from the Editor

I am pleased to present the 1992 edition of *Electric Power In Canada (EPIC)*, which is published by the Electricity Branch of the Department of Natural Resources Canada (formerly Department of Energy, Mines and Resources Canada). The primary purpose of this publication is to provide a comprehensive review of the electric power industry in Canada. In September 1992, the Electricity Branch conducted a readership survey asking for your suggestions on ways to improve EPIC. We would like to take this opportunity to thank those who responded to our request, and we are pleased to report the major results of the survey as follows:

- 80% of the 250 responses received, rated the report as "excellent";
- 80% of the readers use EPIC primarily for general information, and 51% use it in the preparation of reports;
- 57% of the respondents said they found the data easy to locate and 54% said they found the technical terms easy to understand;
- According to our readers, the four major interest areas of the publication are *Electricity Demand and Supply; Electricity Outlook; Electricity Costing and Pricing; and, Electricity and the Environment.*

Although the results appear promising, the Electricity Branch would like to undertake another readership survey this year for the purpose of continuous quality improvement. Again, a questionnaire and a postage-paid mailing envelope are inserted in the 1992 issue of EPIC, and we would ask that you take a few minutes to complete the questionnaire and return it to us for tabulation.

Meanwhile, as a result of last year's survey, the following material has been added to EPIC 1992:
a message from the editor and a new summary section reporting highlights of 1992 electrical developments; a detailed report on reliability of electric service for major electric utilities (Chapter 9); a comparison of heat content for fuel used in electricity generation (Chapter 6); and a comparison of peak hours that occurred in the 1992-93 winter period (Chapter 5). In addition, text in most of the chapters, particularly Chapters 3, 4 and 8, has also been substantially revised. We are currently studying the feasibility of making EPIC data available electronically.

Also, we have deleted some of the appendices as they were found to be less useful. This includes Appendix B: *Chronology of Canadian Electrical Developments and Chronology of Regional Interconnections*; Appendix C: *Remaining Hydroelectric Potential in Canada*; and Appendix E: *Demand-Side Management Programs*. Some of the deleted material can be obtained from the publications listed below, and the remainder can be provided upon request.

The following reports relating at least in part to electricity can be obtained through the Communications Branch of the Department of Natural Resources Canada (580 Booth Street, Ottawa, Ontario, Canada K1A 0E4): *Demand-Side Management in Canada, Statistical Review of Coal in Canada, Uranium in Canada 1991, Canada's Energy Outlook,* and *Electricity Rates in Canada.*

Finally, the 1992 edition of EPIC is about two months late because of a larger than expected work load this year. We sincerely regret any inconvenience this may have caused. Timely publication was one of the objectives desired by readers, and we will try to do better in the future.

Po-Chih Lee

Po-Chih Lee, Ph.D.
Editor

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Highlights of 1992 Electrical Developments

Electricity Demand

Electricity demand rose only 0.9 per cent in 1992 because of slow growth in the economy. The real Gross Domestic Product grew 0.7 per cent in 1992, recovering from a decline of 1.7 per cent in 1991. Mild weather and conservation efforts were the other factors contributing to the small increase in domestic electricity demand. A comparison of electricity demand by province is summarized as follows:

Electricity Demand in Canada (GWh)

Province	1991	1992	% Change
Newfoundland	10 601	10 696	0.9
Prince Edward Island	761	772	1.4
Nova Scotia	9 779	9 908	1.3
New Brunswick	13 640	13 883	1.8
Quebec	160 803	164 605	2.4
Ontario	142 181	139 383	-2.0
Manitoba	18 013	18 376	2.0
Saskatchewan	13 818	14 590	5.6
Alberta	43 957	45 906	4.4
British Columbia	57 528	57 270	-0.4
Yukon	465	480	3.2
Northwest Territories	570	581	1.9
Canada	**472 117**	**474 450**	**0.9**

Electricity Generation

Electricity generation increased by 2.3 per cent in 1992, which is much greater than the 0.9 per cent increase for domestic electricity demand. The increase is mainly attributed to greater exports to the United States. Of the total electricity generated in 1992, hydroelectric generation accounted for 62 per cent, coal 17 per cent, nuclear 15 per cent, oil 3 per cent, natural gas 2 per cent, and other 1 per cent. Electrical energy production by fuel type and by province in 1992 was as follows:

Electrical Energy Production by Fuel Type and by Province in 1992 (GWh)

Province	Coal	Oil	Gas	Nuclear	Hydro	Other	Total
Nfld.	0	1 801	0	0	34 880	0	36 681
P.E.I.	0	34	0	0	0	0	34
N.S.	5 994	2 676	0	0	896	156	9 722
N.B.	1 195	6 687	0	4 835	2 972	273	15 962
Que.	0	1 125	0	4 600	141 352	0	147 077
Ont.	27 470	649	2 338	66 587	39 719	1 755	138 518
Man.	269	3	7	0	26 434	50	26 763
Sask.	9 957	46	891	0	3 055	178	14 127
Alta.	38 677	0	5 888	0	1 585	1 370	47 520
B.C.	0	338	1 669	0	60 555	1 496	64 058
Yukon	0	61	0	0	419	0	480
NWT	0	219	95	0	267	0	581
Canada	**83 562**	**13 639**	**10 888**	**76 022**	**312 134**	**5 278**	**501 523**

Capacity Additions

Because of the anticipated slow growth of the economy, there were only a few capacity additions. A total of 2849 MW was added in 1992. Of this total, 1405 MW was hydro, 935 MW nuclear, 300 MW coal, and 209 oil. By the end of 1992, total installed generating capacity by fuel type and by province was as follows:

Installed Generating Capacity by Fuel Type and by Province in 1992 (MW)

Province	Coal	Oil	Gas	Nuclear	Hydro	Other	Total
Nfld.	0	792	0	0	6 650	5	7 447
P.E.I	0	122	0	0	0	0	122
N.S.	1 332	589	0	0	390	19	2 330
N.B.	418	1 949	0	680	903	87	4 037
Que.	0	1 307	8	685	29 099	5	31 104
Ont.	10 653	2 709	688	12 622	7 191	106	33 969
Man.	369	19	4	0	4 897	23	5 312
Sask.	1 831	22	433	0	836	22	3 144
Alta.	4 861	18	2032	0	733	336	7 980
B.C.	0	243	1030	0	10 849	367	12 489
Yukon	0	58	0	0	77	0	135
NWT	0	133	20	0	51	0	204
Canada	**19 464**	**7 961**	**4215**	**13 987**	**61 676**	**970**	**108 273**

Electricity Exports to the United States

In 1992, electricity exports to the United States increased 32 per cent over 1991, reaching 26 220 GWh, while imports from the United States declined 4 per cent to 1830 GWh. Exports accounted for 5.2 per cent of Canada's total electricity generation in 1992, up from 4.1 per cent in 1991. Export revenue also increased significantly by 26 per cent, from $558 million in 1991 to $708 million in 1992, while import costs increased from $71 million in 1991 to $84 million.

Export increases in 1992 occurred mainly in Quebec, Manitoba, and British Columbia due to improved water flows in these provinces. The addition of the remaining three units at Manitoba Hydro's Limestone generating station also contributed to the increase in electricity exports.

Capital Investment

Electric utilities spent $12.1 billion on facilities in 1992, accounting for 57 per cent of the total investment in the energy sector and 10 per cent of the total investment in the economy. Of the total, about 52 per cent was for generation, 22 per cent for transmission, 12 per cent for distribution, and 14 per cent for other. As of December 31, 1991, the total outstanding long-term debt of the 15 major electric utilities in Canada was $83 billion. Of this total, about 65 per cent ($54 billion) was borrowed on the domestic market, and 35 per cent ($29 billion) was raised on international markets.

Rate Increases

In 1992, Ontario Hydro had the largest rate increase at 11.8 per cent, followed by Edmonton Power at 8 per cent. B.C. Hydro and Alberta Power had rate increases of 7 per cent each. A weighted average for Canada was about 7.2 per cent. This increase was much higher than the Consumer Price Index, which registered an increase of only 1.5 per cent.

DSM and NUG

It is estimated that about 746 MW of generating capacity and 4151 GWh of energy were saved due to the implementation of demand-side management (DSM) by electric utilities in 1992. Cumulative generating capacity savings as of December 31, 1992, were about 4275 MW. For non-utility generators (NUG), it is estimated that about 503 MW of generating capacity, mainly cogeneration, was added in 1992, and they sold about 1750 GWh of energy to the major electric utilities.

Ownership Structure

On January 9, 1992, the Nova Scotia government announced its intention to privatize the provincial electric utility, Nova Scotia Power Corporation (NSPC) in order to release provincial taxpayers from the financial burden of NSPC 's $2.4 billion debt. Legislation to privatize NSPC was introduced in the provincial legislature and passed on June 19, 1992. NSPC shares were offered for sale and investors responded so well that the share offering closed early. The first official day of operation for NSPC as an investor-owned utility was August 13, 1992.

Chapter 1

The Electric Power Industry in Canada

Industry Structure

The modern electric utility industry began in the 1880's. It evolved from gas and electric carbon-arc commercial and street lighting systems. Thomas Edison's Pearl Street electricity generating station, which opened on September 4, 1882, in New York City, was the first to introduce the modern electric utility system to the world.

Today electricity is vital to almost every aspect of the Canadian economy and is projected to continue to expand its role over the next ten years. From 1947 to the end of 1992, net electricity generation increased at an annual average rate of 5.4 per cent, compared with real Gross Domestic Product of 4.1 per cent, and total population growth of 1.8 per cent. Canada's electric power industry is made up of provincial Crown corporations, investor-owned utilities, municipal utilities and industrial establishments. The federal role regarding electricity is restricted to nuclear energy and international and interprovincial trade.

Under the Canadian constitution, electricity is primarily within the jurisdiction of the provinces. As a result, Canada's electrical industry is organized along provincial lines. In most provinces the industry is highly integrated, with the bulk of the generation, transmission and distribution provided by a few dominant utilities. Although some of these utilities are privately owned, most are Crown corporations owned by the provinces. The dominant utilities are listed in Table 1.1 and who does what in the electric power industry is summarized in Table 1.2.

Among the major electric utilities, seven are provincially owned, five are investor owned, two are municipally owned, and two are territorial Crown corporations. In 1992, provincial electric utilities owned about 83 per cent of Canada's total installed generating capacity and produced about 79 per cent of total generated electricity. The five investor-owned utilities accounted for 8 per cent of all Canadian electric utility capacity and produced about 9.6 per cent of total electricity. Municipally owned utilities accounted for 1.4 per cent of capacity ownership, and also produced 1.4 per cent of total generated electricity. The two territorial Crown corporations accounted for 0.3 per cent and 0.2 per cent of capacity and generation respectively.

In addition to the 16 major electric utilities, there are about 60 industrial establishments generating electricity mainly for their own use. A few also sell energy to municipal distribution systems or utilities. These industries are concentrated in the pulp and paper, mining and aluminum smelting sectors. In 1992, industrial establishments owned about 5.6 per cent of total capacity and produced about 7.9 per cent of total generated electricity in Canada, as shown in Table 1.3.

As well as the major electric utilities and industrial establishments, there are about 364 smaller utilities across Canada, of which 87 per cent are located in Ontario. Most of these small utilities are owned by municipalities. They do not own generating capacity; instead, they usually purchase power from the major utility in their province. Several small investor-owned utilities, however, have their own generating capacity. In 1992, small utilities accounted for 1.4 per cent of total Canadian capacity and produced 1.5 per cent of electrical energy.

Electricity and the Economy

The electric power industry has a significant presence within the Canadian economy. As indicated in Table 1.4, there were almost 95 000 people directly employed by the industry

in 1992, (about 0.8 per cent of total Canadian employment), down from 1.1 per cent in 1991, reflecting the severe restructuring of Canada's electric power industry in 1992. Total revenue increased to about $24.5 billion in 1992. Of this total, approximately $708 million or 2.9 per cent came from export earnings. The electric power industry has steadily increased its contribution to Canada's Gross Domestic Product, from 2.3 per cent in 1960, to 2.5 per cent in 1970, to 3.0 per cent in 1980, to 3.3 per cent in 1991, to 3.7 per cent in 1992.

The electric power industry had the largest investment share in the energy sector in 1992, with total capital expenditures of $12.1 billion accounting for about 57 per cent of the total investment in the energy sector, and 10 per cent of the total investment in the economy. Total assets of the industry were about $138 billion in 1992, accounting for about 7.5 per cent of the capital stock of the economy, excluding the residential sector. This reflects the capital-intensive nature of the electric power industry. Ontario Hydro, Hydro-Québec and B.C. Hydro were the three largest electric utilities in Canada and, in terms of assets, ranked third, fourth, and twelfth respectively among all Canadian companies.

Canadian Electric Utilities

Newfoundland

In Newfoundland, the generation and distribution of electricity is dominated by two utilities, Newfoundland Light & Power Company Limited (NLPC) and Newfoundland and Labrador Hydro (NLH). Together, NLPC and NLH serve about 226 000 customers.

NLPC, an investor-owned utility, is the primary retailer of electricity on the island. NLPC was incorporated in 1966 through the amalgamation of St. John's Electric Light Company Limited, United Towns Electric Company Limited and Union Electric Light and Power Company. Approximately 92 per cent of the company's power supply is purchased from NLH, with the balance generated by its own hydro stations. NLPC is a subsidiary of FORTIS Inc., formed in 1987, which owns and operates subsidiaries that include NLPC, a residential mortgage company, and a property investment company.

NLH is a provincial Crown corporation, whose mandate is to generate and transmit electricity in the province. It was established by an act of the provincial legislature in 1954 and was incorporated in 1975. It is the parent company of a group that includes Churchill Falls (Labrador) Corporation (CFLCo), the Lower Churchill Development Corporation (LCDC), Twin Falls Power Corporation Limited, Gull Island Power Co. Ltd., and the Power Distribution District of Newfoundland and Labrador. NLH has 51 per cent ownership in LCDC; the Government of Canada owns the remaining 49 per cent. Through CFLCo, NLH owns and operates the Churchill Falls plant, one of the largest power facilities in the world. NLH's on-island capacity is generated from oil and hydro sources.

Prince Edward Island

Maritime Electric Company Limited (MECL) is an investor-owned utility that has provided electricity service to Prince Edward Island since 1918. The company owns and operates a fully integrated electric utility system providing for the generation, transmission and distribution of electricity throughout the island. MECL operates two oil-fired generating plants on the island, and has a 10 per cent equity interest in New Brunswick Electric Power Commission's coal/oil-fired No. 2 unit located in Dalhousie, N.B. Two submarine cables link MECL's system with New Brunswick's power grid. MECL is the major distributor on the island, serving about 52 000 customers. A municipal utility in the

town of Summerside has its own distribution system and purchases power from MECL.

Nova Scotia

The Nova Scotia Power Corporation (NSPC) was incorporated in 1973. Prior to 1992, it was a provincial Crown corporation producing and distributing electricity throughout the province. However, on January 9, 1992, the Nova Scotia government announced the privatization of this utility in order to release provincial taxpayers from the financial burden associated with NSPC's $2.4 billion debt. An Act respecting the privatization of NSPC was introduced in the provincial Legislature on April 16, 1992, and passed on June 19, 1992. Nova Scotia Power shares were offered for sale on July 7, 1992, and investors responded so well that share offering closed on August 12, 1992. Nova Scotia Power Corporation commenced operation as an investor-owned utility on August 13, 1992. NSPC generates most of its electricity from thermal energy, with more than 64 per cent of the production coming from coal. The utility also maintains hydro-generation and oil-fired facilities, and purchases power from New Brunswick. The largest portion of the province's total production is derived from the Lingan generating station located on Cape Breton Island. In 1992, NSPC served about 401 000 customers.

New Brunswick

The New Brunswick Electric Power Commission (NB Power) was established by an act of the New Brunswick Legislature in 1920. The mandate of NB Power is to generate and distribute power under public ownership to all areas of the province. The utility owns and operates 15 generating stations, and electricity is generated from a balance of nuclear, hydro and thermal sources. NB Power also purchases energy from Quebec. In 1992, NB Power directly provided electricity to 316 000 customers and indirectly served an additional 40 000 customers through sales to two municipal utilities.

Quebec

Hydro-Québec is a Crown corporation, established by the provincial Legislative Assembly in April 1944. It is responsible for the generation, transmission and distribution of most of the electricity sold in Quebec, and also sells and purchases both power and energy under agreement with neighbouring electrical systems in Canada and the United States. Almost all of the electricity generated by Hydro-Québec at its stations throughout the province is from hydraulic sources. The utility currently serves about 3.3 million customers, and ranks among North America's largest electric utilities in terms of assets and volume of sales.

Hydro-Québec has six wholly owned subsidiaries: the Société d'énergie de la Baie James, which carried out the construction of Phase 1 of La Grande complex and which now manages large construction projects for Hydro-Québec; Hydro-Québec International, which provides engineering and consulting services abroad for electric power projects; Cedars Rapids Transmission Company Limited, which owns and opèrates a transmission line between Quebec and New York State; Somarex Inc., which was created to finance, construct and operate a transmission line in the State of Maine; Nouveler Inc., which promotes energy efficiency and alternative energy sources; and Société 2312-0843 Quebec Inc., which is a partner in the limited partnership société en commandite HydrogenAL II and which, on January 1, 1990, became a partner in the limited partnerships société en commandite HydrogenAL and société en commandite ArgonAL, whose other partner is Canadian Liquid Air Ltd.

Hydro-Québec has a 34.2 per cent interest in Churchill Falls (Labrador) Corporation Limited, which operates the Churchill Falls power plant. Under the contract, Hydro-Québec buys the bulk of the Labrador station's 5,429 MW output at an average price of 0.3 cents/kWh. It also has a 50 per cent interest in HydrogenAL Inc., HydrogenAL II Inc., and ArgonAL Inc.

By the end of 1992, Hydro-Québec had a total of 80 generating stations: 53 hydroelectric, 26 conventional thermal, and one nuclear.

Ontario

Ontario Hydro is a provincially owned corporation, established in 1906 by a special statute of the Province of Ontario. Ontario Hydro is a financially self-sustaining corporation without share capital. Bonds and notes issued to the public are guaranteed by the Province. Under the Power Corporation Act, the main responsibility of Ontario Hydro is to generate, supply and deliver electricity throughout Ontario. It also produces and sells steam and hot water as primary products. Working with municipal utilities and with the Canadian Standards Association, Ontario Hydro is responsible for the inspection and approval of electrical equipment and wiring throughout the province.

Ontario Hydro sells wholesale electric power to 311 municipal utilities, which in turn retail it to customers in their service areas. Ontario Hydro also directly serves about 108 large industrial customers and more than 940 000 small business and residential customers in rural and remote areas. In 1992, more than 3.7 million customers were served by Ontario Hydro and the municipal utilities in the province.
Ontario Hydro operates 82 power stations: 69 hydroelectric, 8 conventional thermal, and 5 nuclear. Ontario Hydro also operates an extensive transmission system of about 135 000 km across the province.

The year 1992 marked the beginning of a new era for Ontario Hydro. A number of factors combined to confront the corporation with perhaps the most serious crisis in its 86-year history. Two compelling requirements were brought into focus: one was a need to reduce costs in order to halt spiralling rate increases and to control and reduce the company's indebtedness; and the other was a need to re-structure the corporation to make it more efficient and more competitive.

In Ontario, there are also a number of small regional utilities. An example is Great Lakes Power Limited, a private hydroelectric generation and distribution utility operating in Sault Ste. Marie and west of the Algoma district of Ontario. In 1992, the utility served over 10 000 customers in northern Ontario directly, and another 30 000 indirectly.

Manitoba

The Manitoba Hydro-Electric Board (Manitoba Hydro) is a Crown corporation established in 1949 by the provincial legislature. It has broad powers to provide electric power throughout the province and operates under the 1970 Manitoba Hydro Act. Almost all of the province's electric power is produced by Manitoba Hydro at its generating stations on the Churchill/Nelson river system in northern Manitoba. Manitoba Hydro distributes electricity to consumers throughout the province, except for the central portion of Winnipeg, which is served by the municipally owned Winnipeg Hydro. Manitoba Hydro and Winnipeg Hydro operate as an integrated electrical generation and transmission system. In 1992, Manitoba Hydro served more than 377 000 customers directly, and Winnipeg Hydro served over 110 000 customers.

Manitoba Hydro produces electricity by operating 12 hydroelectric generating stations, two thermal generating stations, and 13 diesel sites. Limestone Hydro Project (10x133 MW)

was completed in 1992, ahead of schedule and under budget.

Saskatchewan

The Saskatchewan Power Corporation (SaskPower) is a Crown corporation operating under the 1950 Power Corporation Act. Under the Act, the mandate of SaskPower includes the generation, transmission and distribution of electricity. At the end of 1992, the corporation served more than 411 000 customers with electricity. The bulk of the electricity generated by SaskPower is from thermal sources. In 1992, coal-fired stations produced about 73 per cent of total electricity, followed by hydro at 22 per cent, and natural gas at 5 per cent.

The Shand Power Station (1x300 MW) was completed and began producing electricity in 1992. Shand is one of Canada's most environmentally advanced coal-fired stations.

In 1988, the gas operations of the corporation became separate companies within SaskPower. The parent company of the gas operations is the Saskatchewan Energy Corporation (SaskEnergy). In 1989, SaskEnergy became a totally separate company.

Alberta

There are three major electric utilities in Alberta: TransAlta Utilities Corporation, Alberta Power Limited, and Edmonton Power. Together, they supply about 92 per cent of Alberta's electrical energy requirements. All are linked by a transmission network largely owned by TransAlta. The remaining 8 per cent of Alberta's electrical energy is supplied by industry. Over 81 per cent of the electricity generated by Alberta utilities is produced by large coal-fired generating stations.

TransAlta Utilities Corporation, formerly Calgary Power Limited, is the largest investor-owned electric utility in Canada. The company was incorporated under the laws of Canada and has been engaged in the production and distribution of electricity in the Province of Alberta since 1911. About 63 per cent of the electric energy requirements of Alberta are supplied by TransAlta, to over half of the population. In 1992, more than 312 000 customers were served directly by TransAlta, while another 315 000 customers were served indirectly through wholesale contracts. TransAlta has a number of subsidiaries: TransAlta Resources Corporation, its principal subsidiary, holds investment in non-regulated activities including TransAlta Technologies Inc.; TransAlta Energy Systems Corporation which provides building automation and energy management services across Canada; TransAlta Fly Ash Ltd.; Kanelk Transmission Company Limited; and Farm Electric Services Ltd.

Alberta Power Limited, incorporated in 1972, is another investor-owned electric utility in Alberta, and a subsidiary of Canadian Utilities Limited. The activity of the company is concentrated in east-central and northern Alberta. In 1992, Alberta Power supplied about 19 per cent of total Alberta electricity requirements and served about 161 000 customers.

Edmonton Power has the largest generating capacity of any municipally owned utility in Canada. Since its creation in 1902, Edmonton Power has kept pace with the growth and development of Edmonton. In 1992, the utility produced about 13 per cent of Alberta's electricity requirements and served more than 251 000 customers. Edmonton Power purchased about 2 per cent of its electricity requirements from TransAlta Utilities and Alberta Power.

In 1992, Edmonton City Council created the Edmonton Power Authority which went into effect on January 1, 1993. The status as an Authority was an interim step in incorporating

Edmonton Power as a wholly-owned subsidiary of the city rather than a department of the city. It was felt that Edmonton Power would best serve its customers by operating under subsidiary status.

British Columbia

British Columbia Hydro & Power Authority (B.C. Hydro) was incorporated in 1962 and is a Crown corporation operating in British Columbia. B.C. Hydro provides electrical service throughout the province, with the exception of the southern interior which is served by West Kootenay Power and Light Company, Limited. B.C. Hydro is the third largest electric utility in Canada. It generates, transmits and distributes electricity to more than 1.3 million customers in a service area which contains more than 92 per cent of the population of the province.

In 1988, B.C. Hydro proceeded with a corporate restructuring that resulted in the privatization of its mainland gas operations and its rail operations, and the creation of a number of subsidiaries. B.C. Hydro International Limited provides consulting services in the areas of engineering and utility operations to Canadian and international customers. British Columbia Power Export Corporation (POWEREX) was established to market the province's firm electricity exports. POWEREX negotiates and administers firm export sales agreements with U.S. utilities and purchase agreements with electricity producers, and will make arrangements with Hydro for services such as transmission facilities. Powertech Labs Inc. was formed to provide research, testing and consulting work for electrical technological development. Westech Information Systems Inc. was created in 1989 to offer a wide range of professional services, including the design, development and maintenance of integrated computer systems. Western Integrated Technologies Inc. was also created in 1989 to provide technical support and data processing operations.

West Kootenay Power is an investor-owned utility supplying electric service in the southern interior of British Columbia. The company generates and distributes hydroelectricity directly to more than 63 000 customers in its service area. It also supplies power to seven wholesale customers, who in turn serve almost 38 000 customers. West Kootenay Power is owned by UtiliCorp United Inc. of Kansas City, Missouri.

Yukon

Two utilities provide electrical service to about 12 000 customers in the Yukon. The largest of these, in terms of revenues and generating capacity, is the Yukon Energy Corporation. It is a territorial Crown corporation that has taken over responsibility for the Yukon assets of the Northern Canada Power Commission (NCPC). The Yukon Development Corporation (the parent corporation of the Yukon Energy Corporation) has entered into a five-year management services agreement with the Yukon Electrical Company Limited (YECL). Under the terms of the agreement, YECL will operate the Yukon Energy Corporation's assets, purchase the electricity generated, and distribute it to the Energy Corporation's customers. The Energy Corporation's customers include all of the Yukon's major industries and 13 per cent of the Yukon's non-industrial customers.

In addition to its responsibilities to the Yukon Energy Corporation, YECL (a subsidiary of Canadian Utilities Limited) also generates and distributes power to its own customers. YECL serves 18 communities in the Yukon, including Whitehorse. It purchases the majority of its electrical requirements from the Yukon Energy Corporation.

Northwest Territories

Electrical service to about 14 000 customers in the Northwest Territories is provided by the Northwest Territories Power Corporation (NWTPC) and Northland Utilities Enterprises Limited (Northland). The largest of these, in terms of revenues and generating capacity, is the NWTPC. It is a territorial Crown corporation, which in 1988 took over responsibility for the Northwest Territories' assets of the NCPC. NWTPC provides electrical service to 51 communities in the N.W.T. and wholesales hydro-power to Northland.

Northland is an investor-owned utility and is a subsidiary of Canadian Utilities Limited. It provides electrical service to seven communities in the south-western region of the N.W.T.

Tables referred to in this chapter are on the following pages.

Tables & Figures

Table 1.1
Canada's Major Electric Utilities by Province

Province	Electric Utility	Ownership
Newfoundland	Newfoundland and Labrador Hydro Newfoundland Light & Power Company Limited	Provincial Private
Prince Edward Island	Maritime Electric Company Limited	Private
Nova Scotia	Nova Scotia Power Incorporated	Private
New Brunswick	New Brunswick Electric Power Commission	Provincial
Quebec	Hydro-Québec	Provincial
Ontario	Ontario Hydro	Provincial
Manitoba	The Manitoba Hydro-Electric Board City of Winnipeg Hydro-Electric System	Provincial Municipal
Saskatchewan	Saskatchewan Power Corporation	Provincial
Alberta	Alberta Power Limited Edmonton Power TransAlta Utilities Corporation	Private Municipal Private
British Columbia	British Columbia Hydro & Power Authority	Provincial
Yukon	Yukon Energy Corporation	Territorial
Northwest Territories	Northwest Territories Power Corporation	Territorial

Source: Department of Natural Resources Canada

Table 1.2
Electricity in Canada - Who Does What

Function	Provinces	Canada
R&D	Utilities, Canadian Electrical Association	Atomic Energy of Canada Limited (AECL)
Planning	Utilities Governments	
Generation Design	Utilities	Atomic Energy of Canada Limited (AECL)
Generation Operation	Utilities	
Transmission	Utilities	
Distribution	Utilities	
Project Regulation	Regulatory Board or Equivalent	Atomic Energy Control Board (AECB)
Rate Regulation	Regulatory Board or Equivalent	
Export Regulation		National Energy Board
Interprovincial Trade Regulation	Utilities (unwritten rules)	National Energy Board (authority limited)
Environmental Regulation	Provincial Mechanisms	Federal Environmental Assessment Review Office (FEARO)

Source: Department of Natural Resources

Table 1.3
Electrical Capacity and Production by Utilities and Industrial Establishments, 1930-92

	Installed Generating Capacity			Energy Production		
Year	Utilities (%)	Industrial Establishments (%)	Capacity (MW)	Utilities (%)	Industrial Establishments (%)	Generation (GWh)
1930	83	17	5 573	93	7	19 468
1940	84	16	8 104	91	9	33 062
1950	83	17	11 076	88	12	55 037
1960	80	20	23 035	78	22	114 378
1965	82	18	29 348	77	23	144 274
1970	88	12	42 826	84	16	204 723
1975	90	10	61 352	87	13	273 392
1980	92	8	81 999	89	11	367 306
1985	93	7	97 020	92	8	447 182
1988	94	6	101 055	92	8	490 672
1989	94	6	101 960	92	8	482 152
1990	94	6	102 947	91	9	465 744
1991	94	6	105 424	92	8	490 448
1992	94	6	108 273	92	8	501 523

Source: Electric Power Statistics, Volume II, Statistics Canada, 57-202, 57-001

Table 1.4
Electric Utility Assets, Revenue and Employees, 1992

Utility	Assets ($ millions)	Revenue ($ millions)	Employees (persons)
Major Utilities:			
Newfoundland and Labrador Hydro	2 286	369	1 392
Newfoundland Light & Power Co. Ltd.	478	344	997
Maritime Electric Co. Ltd.	130	81	239
Nova Scotia Power Corporation*	2 323	674	2 437
New Brunswick Electric Power Commission*	3 656	924	3 163
Hydro-Québec	44 864	6 807	21 161
Ontario Hydro	46 671	7 768	34 839
The Manitoba Hydro-Electric Board*	5 935	757	4 302
City of Winnipeg Hydro-Electric System	162	117	613
Saskatchewan Power Corporation	3 246	720	2 584
TransAlta Utilities	4 176	1 096	2 483
Edmonton Power	1 927	389	1 146
Alberta Power Limited	1 896	534	1 566
B.C. Hydro and Power Authority*	9 608	2 072	6 048
Yukon Energy Corporation*	119	27	111
Northwest Territories Power Corporation*	260	98	300
Other Utilities	10 218	1 700	11 613
Canada	137 955	24 477	94 994

*As at March 31, 1992

Source: Electric utilities' annual reports

Canadian Electricity in the International Context

World Primary Energy Consumption

This chapter compares Canada's electricity supply, demand, trade, intensity and pricing with those of selected other countries in the world. The data used in this chapter were obtained from reputable sources such as the United Nations' Energy Statistics Yearbook and the International Energy Annual published by the Energy Information Administration of the U.S. Department of Energy. Data on the comparison of electricity prices by sector was taken from an annual survey produced by the Electricity Branch of Canada's Department of Natural Resources.

During the past 10 years, the world's total primary energy consumption (petroleum, natural gas, coal, hydroelectricity, and nuclear electricity) has increased steadily at an average annual rate of 2.4 per cent. However, individual primary energy forms grew at different rates: petroleum, coal and hydroelectricity increased at a rate below average, while natural gas and nuclear rose substantially above average.

World consumption of petroleum increased from 59.5 million barrels (about 364 petajoules) per day in 1982 to 66.6 million barrels per day in 1991, with an average annual growth rate of only 1.3 per cent. Petroleum is still the largest component of the world's total primary energy consumption, accounting for about 39 per cent. The slow growth of petroleum demand is mainly attributed to a depressed world economy in general, fuel substitution, and conservation efforts.

World consumption of dry natural gas rose from 53.1 trillion cubic feet (about 56 000 petajoules or 1.5 trillion cubic metres) in 1982 to 76.0 trillion cubic feet (2.2 trillion cubic metres) in 1991, an average annual growth rate of 4.1 per cent. The use of natural gas for space heating and power generation has been popular in recent years because of its competitive price and reduced environmental impact.

World consumption of coal rose from 4.3 billion short tons (about 116 000 petajoules) in 1982 to 5.1 billion short tons in 1991, with an average annual growth rate of 1.9 per cent. The four largest consumers in 1991 were: China at 1.2 billion, the United States at 0.9 billion, the Soviet Union* at 0.7 billion, and Germany at 0.4 million short tons. Because of its emissions problem, the growth of coal demand is expected to remain slow.

World consumption of hydroelectric power increased from 1822 TWh (about 6 647 petajoules) in 1982 to 2145 TWh in 1992, with an average annual growth rate of 1.9 per cent. As most of the economical hydro sites have been developed in the world, an increase of hydroelectricity demand is expected to be slow. The U.S., Canada, Soviet Union, and Brazil were the four largest hydroelectricity consumers in the world in 1991.

World consumption of nuclear energy has grown the fastest during the past 10 years, rising from 866 TWh in 1982 to 1982 TWh in 1991, with an average annual growth rate of 9.6 per cent, four times larger than that of the world's total primary energy consumption.

In the primary energy consumption, a great portion of coal consumption is used for baseload electricity generation. The same is true for petroleum and natural gas consumption. However, petroleum is mainly used for peak demand, while natural gas is used for both peak demand and baseload. Because of the difficulty of estimating the portions of petroleum, coal and natural gas used for electricity generation at the world level, it is hard to present the world's total

**The former Soviet Union ceased to exist on December 25, 1991.*

primary energy consumption delivered in the form of electricity.

Based on the U.S. Department of Energy's estimate, world total net electricity consumption (excluding transmission and distribution losses) rose from 7662 TWh in 1982 to 10 482 TWh in 1991, an average annual growth rate of 3.5 per cent, much greater than the world's total primary energy consumption of 2.4 per cent registered during the same period 1982-91.

Canada holds a significant place in the world's electric power industry. Canada is not only a world leader in long-distance electric power transmission, but also the largest hydroelectric power producer, an important consumer, and a big exporter.

Installed Generating Capacity

During the past 20 years, the growth of Canada's electric power industry has kept in line with the world's electric power industry as a whole. World installed generating capacity rose from 1113 GW in 1970 to 2746 GW in 1990, with an average annual growth rate of 4.6 per cent. While Canada's system increased from 43 GW to 104 GW, with an average annual growth rate of 4.5 per cent during the same period 1970-1990. The main difference between these two systems is that Canada's system is predominately hydro, accounting for 57 per cent of total installed capacity in 1990, and total world generating capacity is predominately conventional thermal, accounting for 64 per cent of the total.

Table 2.1 reports the 20 largest electrical systems in the world, and the world total for all 190 countries and areas. Of this world total, conventional thermal (consisting of installed capacity from coal, oil and natural gas) accounted for 1772 GW (64.5 per cent); hydro 628 GW (22.8 per cent); nuclear 337 GW (12.3 per cent); and geothermal only 9 GW (0.4 per cent).

In 1990, North America had 33 per cent of the world's total installed generating capacity, dropping one percentage point from 1989, followed by Europe at 25 per cent, Asia at 21 per cent, up by one percentage point from 1989, the Soviet Union at 12 per cent, South America at 4 per cent, Africa at 3 per cent, and Oceania at 2 per cent.

The U.S. electric power industry was the largest in the world, with a total installed capacity of 775 GW, accounting for 28 per cent of the world total. The Soviet Union was second, with an installed capacity of 333 GW, and Japan was third with 195 GW. The United States led in installed capacity for every fuel type: U.S. conventional thermal accounted for 32 per cent of the world's thermal capacity; hydro for 13 per cent; nuclear for 32 per cent; and geothermal for 52 per cent.

Canada ranked fourth in the world with an installed generating capacity of about 104 GW (behind the United States, Soviet Union, and Japan), accounting for 4 per cent of the world total. In terms of fuel type, Canada's hydro capacity is the third largest in the world, next to the U.S. and the Soviet Union. Canada's nuclear capacity is sixth in the world, and its conventional thermal capacity is ninth.

Electricity Generation

World electricity generation grew almost at the same rate as generating capacity has during the past 20 years. World electricity generation increased from 4908 TWh in 1970 to 11 734 TWh in 1990, with an average annual growth rate of 4.5 per cent. In terms of fuel type, the average growth rate was 3.7 per cent for thermal, 3.1 per cent for hydro, and 17.6 per cent for nuclear. Canada's electrical system

experienced similar growth patterns as did the world as a whole. Canada's total generation rose from 205 TWh in 1970 to 482 TWh in 1990, with an average annual growth rate of 4.4 per cent. By fuel type, thermal grew 4.4 per cent, hydro 3.1 per cent, and nuclear 15.6 per cent for the period 1970-1990. However, hydro was the main source of generation in Canada, accounting for 62 per cent of the Canadian total, as compared with only 18 per cent for the world total.

In 1990, a total of 11 734 TWh of electricity was generated around the world: conventional thermal, mainly from coal- fired stations, accounted for 7551 TWh (64.4 per cent); hydro 2162 TWh (18.4 per cent); nuclear 1982 TWh (16.9 per cent); and geothermal 40 TWh (0.3 per cent). (See Table 2.2.) Although nuclear accounted for only 12.3 per cent of the world's total capacity in 1990, its energy generation share was 16.9 per cent, indicating that most nuclear stations were operating at a relatively high capacity factor compared with conventional thermal stations and hydro plants.

In 1990, North America accounted for 31 per cent of the world's total net electricity generation, a decline of one percentage point from 1989; Europe had 24 per cent; Asia had 22 per cent, up one percentage point; the Soviet Union had 14 per cent; South America had 4 per cent; Africa had 3 per cent, and Oceania had 2 per cent. Asia appeared to be the only region where both generating capacity and production shares were increased in 1990 over 1989, while North America's shares were reduced in both cases.

About 26 per cent of total world electricity generation took place in the United States in 1990. Its conventional thermal generation was 2146 TWh, accounting for 28 per cent of total world conventional thermal. The United States was also the largest nuclear energy producer in the world in 1990, with a total of 577 TWh or 29 per cent of total world nuclear. As a proportion of total national electricity production, however, France's nuclear generation was the largest at about 75 per cent, followed by Belgium at 61 per cent and Sweden at 46 per cent. Canada's nuclear share was a relatively small 15 per cent. The nuclear shares of the United States and the Soviet Union were 19 per cent and 12 per cent respectively.

Canada's total electricity production ranked fifth in the world (behind the U.S., the Soviet Union, Japan and China), with total production of 482 TWh or 4 per cent of the world total. However, Canada was the largest hydroelectric power producer in the world with total generation of more than 297 TWh, accounting for about 14 per cent of the world's total hydroelectric generation (Table 2.2).

Per Capita Electricity Consumption

World per capita electricity consumption was 2207 kWh in 1990. North America had the highest average of 8658 kWh; followed by Oceania at 7163 kWh; the Soviet Union at 5856 kWh; Europe at 5710 kWh; South America at 1504 kWh; Asia at 817 kWh; and Africa at 486 kWh.

Canada's per capita electricity consumption ranked third in the world in 1990 at 18 149 kWh, next only to Norway's 25 083 kWh and Iceland's 18 221 kWh. As Table 2.3 shows, per capita consumption varies significantly among countries. Norway consumed more than 11 times the world average; Canada more than eight times; and the United States five times. Nigeria and India's per capita consumption levels were less than 15 per cent of the world average. Although China was the fourth largest electricity producer in the world, its per capita consumption was only 25 per cent of the world average.

Two principal factors contribute to Canada's large per capita consumption of electricity. Abundant water resources have permitted the development of economical hydroelectric power projects in various regions, making electrical energy relatively inexpensive and plentiful. This has led to relatively high electricity consumption among all energy users, and it has led many electricity-intensive industries to locate in Canada. As well, Canada's northerly location means a long and cold winter, resulting in much electricity being used for space-heating purposes. Currently, about 34 per cent of total households in Canada use electricity for space heating.

Total Electricity Consumption Growth

World electricity consumption grew by approximately 3.5 per cent annually between 1987 and 1990. Among various regions, Asia had the highest electricity consumption growth rate, at 7.6 per cent for the period 1987-90. It was followed by Oceania at 5.2 per cent, South America at 3.6 per cent, Africa at 3.2 per cent, North America at 3.1 per cent, Europe at 2.0 per cent, and the Soviet Union at 1.2 per cent.

As was pointed out earlier, Asia was the only region in the world with increases in both electrical capacity and generation shares in 1990. These increases were mainly attributed to high electricity demand growth, which was the result of relatively high economic growth in the region.

Table 2.4 reports total electricity consumption growth rates during 1987-90, for the 20 largest electricity producers in the world. In general, most of the countries with high consumption growth rates were developing countries. Many of these countries have been engaged in the industrialization of their economies and, as a result, have increased their electrical energy consumption significantly.

Japan was one of the few developed countries with a high electricity consumption growth rate for the same period. Surprisingly, the United Kingdom and Sweden were among the countries with the lowest consumption growth rates in the world during the past four years.

Electricity Trade

Electricity exchanges among countries can provide a wide variety of benefits to the consumers and electric utilities of trading countries. Interconnections improve the economics and security of electricity supply, and they reduce the level of capacity needed to meet peak loads. Interconnections also improve the flexibility of electricity supply, making it possible to minimize costs by replacing the highest-cost generation, such as oil-fired generation, with imported hydroelectric energy.

In 1990, a total of 278 TWh of electricity was exported internationally, accounting for about 2.4 per cent of world production (Table 2.5). These exports took place mainly in North America and Europe, where there are extensive interconnections between electrical generating stations.

Europe, the Soviet Union, and North America accounted for 94 per cent of total world electricity exports in 1990. As shown in Table 2.5, France was the largest electricity exporter in the world in 1990, with a total of more than 52 TWh, accounting for about 19 per cent of total world exports, and 12 per cent of its own total production. The Soviet Union was second, accounting for 13 per cent, and Switzerland was third with 8 per cent of total world exports. Canada was the sixth largest electricity exporter with 18 TWh in 1990, a drop from third place in 1989.

On the import side, the world total was 296 TWh, accounting for 2.5 per cent of total world consumption in 1990 (Table 2.6). Again, Europe and North America were the major trading areas, accounting for 89 per cent of total world imports.

Italy was the largest electricity importer in 1990, with a total of about 36 TWh or 12 per cent of total world imports, and about 14 per cent of its own total consumption. Brazil was second with 27 TWh or 9 per cent of the world total, and the United States was third with 23 TWh or 8 per cent of total world imports. Although the United States was the third largest importer, its total imports accounted for only 0.8 per cent of its total consumption. The great majority of U.S. electricity imports came from Canada.

Among the top six electricity exporters in 1990, four were also top importers: the United States, West Germany, Switzerland and Canada. Canada is usually a net electricity exporter, however, due to meeting emission guidelines and the problems associated with 1990 water flows, Canada imported a substantial amount of electricity from the United States.

Electricity Intensities

Table 2.7 compares the intensity of electricity use in the economies of all 24 member countries in the Organization for Economic Co-operation and Development (OECD), for the period 1960-90. Electricity intensity is defined as total electricity consumption per dollar of gross domestic product (GDP). To facilitate the comparison, all currencies were converted into U.S. dollars at 1985 price levels and exchange rates. Because of the limited availability of data, only OECD countries are included in the table. Among these countries, Norway had the highest electricity intensity, followed by Iceland, Luxembourg, New Zealand, Sweden, Canada, Portugal, and Finland. In 1990, the electricity intensities of these countries were all greater than 1.0 kilowatt hour of electricity consumption per U.S. dollar of GDP, while Switzerland, Japan, Italy, Denmark, and the Netherlands all had electricity intensities of less than 0.6.

Canada's high electricity intensity is a result of several factors, including our relatively cold climate and the fact that a host of electricity-intensive industries are located here. In addition, since the first oil embargo of 1973, a shift in energy use from oil to electricity has occurred in all sectors of the economy.

All 24 OECD-member countries experienced a time-trend increase in electricity intensity between 1960 and 1990, although some minor fluctuations occurred in the United States, the United Kingdom and Japan. In fact, electricity intensities have been steadily declining since 1970 for the U.K., suggesting that electricity use in producing output has been reduced.

Electricity Prices

A comparison of international electricity prices is difficult because of different rate schedules, consumption levels and national currencies. Nevertheless, a reasonable comparison has been established by using average revenue per kilowatt hour in a given sector, under a certain level of consumption, and by converting to U.S. dollars. For a more accurate comparison, purchasing power parities should be used when converted to U.S. dollars. However, such parities are not available for some countries covered in this study and are therefore not taken into consideration.

Tables 2.8, 2.9 and 2.10 summarize electricity prices by sector for 26 cities in 15 selected countries in the world. The results indicate that Canada's electricity prices are highly competitive in the residential, commercial and industrial sectors relative to other countries.

Tables & Figures

Table 2.1
International Comparison of Installed Generating Capacity, 1990*

Country	Conventional Thermal	Hydro	Nuclear	Geothermal	Total
		(GW)			
United States	572	90	108	5	775
Soviet Union⅄	232	64	37	0	333
Japan	125	38	31	0	195
Canada	**31**	**59**	**14**	**0**	**104**
France	23	25	56	0	103
West Germany✦	70	7	23	0	100
China	69	30	0	0	99
India	56	19	2	0	76
United Kingdom	58	4	11	0	73
Italy	37	19	1	1	57
Brazil	7	46	1	0	53
Spain	20	16	7	0	43
Australia	29	7	0	0	37
Sweden	8	16	10	0	34
Poland	29	2	0	0	31
Mexico	20	8	0	1	29
Norway	0	27	0	0	27
South Africa	24	1	1	0	26
East Germany✦	20	2	2	0	23
Czechoslovakia	14	3	4	0	21
World Total**	1 772 (64.5%)	628 (22.8%)	337 (12.3%)	9 (0.4%)	2 746 (100.0%)

* Includes the 20 countries with the largest electrical systems.

** Total for all 190 countries or areas listed in source reference.

⅄ The former Soviet Union ceased to exist on December 25, 1991.

✦ West and East Germany united in the Winter of 1990.

Source: Energy Statistics Yearbook, 1990, United Nations, pp. 372-398.

Table 2.2
International Comparison of Electricity Generation by Fuel Type, 1990*

Country	Conventional Thermal	Hydro	Nuclear	Geothermal	Total
		(TWh)			
United States	2 146	291	577	18	3 031
Soviet Union ⅄	1 281	223	212	0	1 726
Japan	557	96	202	2	857
China	506	111	0	0	618
Canada	**112**	**297**	**73**	**0**	**482**
West Germany ✦	286	18	151	0	454
France	48	57	314	0	420
United Kingdom	246	7	66	0	319
India	214	66	6	0	286
Brazil	13	207	2	0	222
Italy	179	35	0	3	217
South Africa	160	1	4	0	165
Australia	140	15	0	1	155
Spain	70	26	54	0	151
Sweden	5	73	68	0	147
Poland	133	3	0	0	136
Mexico	90	25	3	5	122
Norway	0	121	0	0	122
East Germany ✦	104	2	12	0	117
Czechoslovakia	61	5	24	0	89
World Total**	7 551	2 162	1 982	40	11 734
	(64.4%)	(18.4%)	(16.9%)	(0.3%)	(100%)

* Includes the world's 20 largest electrical energy producers.
** Total for all 190 countries or areas listed in source reference.
⅄ The former Soviet Union ceased to exist on December 25, 1991.
✦ West and East Germany united in the Winter of 1990.

Source: Energy Statistics Yearbook, 1990, United Nations, pp. 428-454.

Table 2.3
International Comparison of Per Capita Electricity Consumption, 1990*

Country	kWh/Person	As Percentage of World Average
Norway	25 083	1 137
Iceland	18 221	826
Canada	**18 149**	**822**
Sweden	17 130	776
Luxembourg	14 054	634
Finland	13 118	594
United States	12 170	551
Australia	9 161	415
New Zealand	8 891	403
West Germany✦	7 420	336
East Germany✦	7 280	330
Belgium	6 754	306
Japan	6 944	315
France	6 662	302
Austria	6 588	299
Soviet Union⅄	5 856	265
United Kingdom	5 761	261
Netherlands	5 423	246
Italy	4 407	200
South Africa	3 952	179
Spain	3 833	174
Poland	3 521	160
Brazil	1 643	74
Argentina	1 601	73
Mexico	1 367	62
Egypt	754	34
China	546	25
India	336	15
Nigeria	91	4
World Average**	2 207	100

* The first ten countries are listed according to their actual global rankings. The remaining countries are given in descending order of consumption; however, since only the most populous countries from each region were selected, the list does not indicate their true global rankings.

** Average for all 190 countries or areas included in source reference.

✦ West and East Germany united in the Winter of 1990.

⅄ The former Soviet Union ceased to exist on December 25, 1991.

Source: Energy Statistics Yearbook, 1990, United Nations, pp. 456-470

Table 2.4
International Comparison of Total Electricity Consumption Growth Rates, 1987-90

Country	Average, 1987-90
India	9.3
China	7.5
Japan	6.0
Mexico	5.6
Australia	5.5
Spain	4.4
Italy	4.3
Brazil	4.1
United States	3.1
South Africa	2.7
West Germany✦	2.7
France	2.4
Canada	**2.1**
United Kingdom	1.8
Czechoslovakia	1.3
Soviet Union⅄	1.2
Sweden	0.7
Norway	0.7
East Germany✦	0.1
Poland	-2.8
World Total*	3.5

* Total for all 190 countries or areas included in source reference.

✦ West and East Germany united in the Winter of 1990.

⅄ The former Soviet Union ceased to exist on Dec. 25, 1991.

Source: Calculated from Energy Statistics Yearbook, 1990, United Nations, pp. 456-470.

Table 2.5
International Comparison of Electricity Exports, 1990*

Country	Exports** (GWh)	Production (GWh)	Percentage of Exports to Production
France	52 112	419 584	12.4
Soviet Union ⅄	36 300	1 726 000	2.1
Switzerland	22 862	55 846	40.9
West Germany ✦	21 700	454 710	4.8
United States	20 526	3 033 058	0.7
Canada	**18 236**	**481 791**	**3.8**
Norway	16 233	121 602	13.3
Sweden	14 672	146 535	10.0
Poland	11 477	135 337	8.5
Belgium	8 509	70 215	12.1
Austria	7 298	50 414	14.5
Czechoslovakia	7 000	89 345	7.8
Denmark	4 925	25 724	19.1
East Germany ✦	4 500	117 292	3.8
Spain	3 628	150 202	2.4
Yugoslavia	3 108	85 905	3.6
South Africa	3 100	164 518	1.9
Mexico	1 950	122 477	1.6
Hong Kong	1 797	28 938	6.2
Brazil	1 741	222 195	0.8
Portugal	1 697	28 529	5.9
Zambia	1 500	7 772	19.3
Uraguay	1 330	7 372	18.0
Italy	922	216 891	0.4
Luxembourg	746	1 374	0.5
Total World Exports***	277 754	11 733 858	2.4

* Includes the world's 25 largest electricity exporters.
** Includes non-cash exchanges.
*** Total for all exporting countries or areas listed in source reference.
⅄ The former Soviet Union ceased to exist on December 25, 1991.
✦ West and East Germany united in the Winter of 1990.

Source: Energy Statistics Yearbook, 1990, United Nations, pp. 456-470.

Table 2.6
International Comparison of Electricity Imports, 1990*

Country	Imports** (GWh)	Consumption (GWh)	Percentage of Imports to Consumption
Italy	35 577	251 546	14.1
Brazil	26 545	246 999	10.7
United States	22 506	3 033 038	0.7
West Germany✦	22 000	455 010	4.8
Switzerland	20 754	53 738	38.6
Canada	**17 781**	**481 336**	**3.7**
Sweden	12 784	144 647	8.8
United Kingdom	11 990	330 922	3.6
Denmark	11 973	32 772	36.5
Hungry	11 127	39 538	28.1
Finland	11 113	65 261	17.0
Poland	10 437	135 297	8.3
Czechoslovakia	10 300	92 645	11.1
Netherlands	9 679	81 074	11.9
Romania	9 476	64 306	14.7
Austria	6 839	49 955	13.7
France	6 674	374 146	1.8
East Germany✦	5 500	118 292	4.6
Bulgaria	5 000	45 700	10.9
Belgium	4 785	66 491	7.2
Luxembourg	4 614	5 242	88.0
Spain	3 208	150 202	2.1
Portugal	1 733	28 566	6.1
China	1 500	619 460	0.2
Greece	1 330	35 713	3.7
Total World Exports***	296 139	11 752 243	2.5

* Includes the world's 25 largest electricity importers.
** Includes non-cash exchanges.
*** Total for all importing countries or areas listed in source reference.
✦ West and East Germany united in the Winter of 1990.

Source: Energy Statistics Yearbook, 1990, United Nations, pp. 456-470.

Table 2.7
International Comparison of Electricity Intensity*

Country**	1960	1970	1980	1988	1989	1990
			(kWh/U.S. $1985)			
Norway	1.52	1.83	1.70	1.68	1.68	1.68
Canada	**0.94**	**1.05**	**1.13**	**1.22**	**1.22**	**1.20**
Luxembourg	0.93	1.56	1.30	1.30	1.24	1.31
Sweden	0.71	0.86	1.06	1.33	1.30	1.23
Iceland	0.62	1.05	1.20	1.25	1.38	1.41
New Zealand	0.59	0.84	1.14	1.33	1.24	1.30
United Kingdom	0.53	0.73	0.69	0.62	0.61	0.62
Austria	0.52	0.58	0.62	0.65	0.66	0.66
Portugal	0.49	0.60	0.86	1.05	1.08	1.10
United States	0.47	0.62	0.69	0.65	0.66	0.66
Finland	0.44	0.66	0.85	1.02	0.98	1.02
Belgium	0.44	0.55	0.66	0.72	0.71	0.71
West Germany✦	0.43	0.56	0.63	0.64	0.63	0.62
Japan	0.43	0.52	0.53	0.50	0.50	0.51
Australia	0.39	0.55	0.70	0.79	0.80	0.81
Switzerland	0.37	0.37	0.44	0.48	0.49	0.51
Italy	0.36	0.45	0.48	0.50	0.50	0.51
France	0.35	0.42	0.54	0.63	0.62	0.62
Spain	0.34	0.50	0.71	0.72	0.73	0.73
Ireland	0.33	0.58	0.66	0.65	0.64	0.63
Netherlands	0.30	0.45	0.54	0.57	0.56	0.56
Greece	0.24	0.50	0.74	0.95	0.96	0.98
Denmark	0.20	0.39	0.51	0.53	0.53	0.52
Turkey	0.19	0.34	0.59	0.76	0.81	0.82

* Electricity intensity is defined as total electricity consumption per dollar of gross domestic product.

** Due to limited availability of data, table includes only OECD-member countries.

✦ West and East Germany united in the winter of 1990.

Source: *Real gross domestic product in U.S. dollars was obtained from National Accounts, 1960-1990, Dept. of Economics and Statistics, OECD, February 1992. Electrical energy data were obtained from Energy Statistics Yearbook, United Nations, various issues.*

Table 2.8
International Comparison of Electricity Prices in the Residential Sector, January 1993*

City	Residential Country	Prices (U.S. cents/kWh)
Tokyo	Japan	15.90
New York	United States	14.53
Madrid	Spain	14.44
Brussels	Belgium	13.80
London	United Kingdom	12.32
Geneva	Switzerland	12.15
Paris	France	11.41
Chicago	United States	11.34
Boston	United States	11.29
Sao Paulo	Brazil	10.99
Los Angeles	United States	10.37
Rotterdam	Holland	10.03
Detroit	United States	9.80
Taipei	Taiwan	9.37
Houston	United States	9.26
Bankok	Thailand	8.78
Kuala Lumpur	Malaysia	8.69
Stockholm	Sweden	8.62
Singapore	Singapore	8.24
Toronto	**Canada**	**8.15**
Minneapolis	United States	7.85
Oslo	Norway	6.97
Ottawa	**Canada**	**6.21**
Calgary	**Canada**	**5.66**
Montreal	**Canada**	**5.42**
Vancouver	**Canada**	**5.37**
Portland	United States	5.30
Sydney	Australia	5.19
Winnipeg	**Canada**	**5.13**
New Delhi	India	4.87
Seattle	United States	4.10

* Based on typical monthly consumption of 750 kWh. Tokyo is based on monthly consumption of 625 kWh.

Source: Canadian data were obtained from the Electricity Branch, Department of Natural Resources Canada. Data for other countries were obtained from a survey undertaken by the Electricity Branch, Department of Natural Resources Canada, February 1993.

Table 2.9
International Comparison of Electricity Prices in the Commercial Sector, January 1993*

City	Country	Commercial Prices (U.S.cents/kWh)
Tokyo	Japan	15.57
New York	United States	14.96
London	United Kingdom	14.95
Geneva	Switzerland	13.92
Brussels	Belgium	13.20
Madrid	Spain	12.81
Los Angeles	United States	12.70
Sydney	Australia	10.84
Boston	United States	10.45
Detroit	United States	10.32
Rotterdam	Holland	10.17
Chicago	United States	9.91
Kuala Lumpur	Malaysia	9.23
Paris	France	8.61
Toronto	**Canada**	**8.25**
Houston	United States	8.14
Bangkok	Thailand	8.12
Taipei	Taiwan	7.88
Oslo	Norway	7.47
Stockholm	Sweden	7.22
New Delhi	India	6.87
Singapore	Singapore	6.72
Sao Paulo	Brazil	6.67
Montreal	**Canada**	**6.66**
Minneapolis	United States	6.46
Ottawa	**Canada**	**5.99**
Calgary	**Canada**	**5.68**
Portland	United States	5.33
Winnipeg	**Canada**	**5.15**
Vancouver	**Canada**	**4.82**
Seattle	United States	4.77

* Based on typical monthly billing demand of 100 kW and energy consumption of 25 000 kWh. Tokyo is based on a monthly billing of 98 kW and energy consumption of 13 333 kWh.

Source: Canadian data were obtained from the Electricity Branch, Department of Natural Resources Canada. Data for other countries were obtained from a survey undertaken by the Electricity Branch, Department of Natural Resources Canada, February 1993

Table 2.10
International Comparison of Electricity Prices in the Industrial Sector, January 1993*

City	Country	Industrial Prices (U.S. cents/kWh)
London	United Kingdom	12.59
Tokyo	Japan	12.34
Brussels	Belgium	11.03
Geneva	Switzerland	10.27
New York	United States	10.21
Madrid	Spain	9.87
Boston	United States	7.95
Los Angeles	United States	7.70
Chicago	United States	7.68
Detroit	United States	7.59
New Delhi	India	7.49
Rotterdam	Holland	7.43
Kuala Lumpur	Malaysia	7.31
Taipei	Taiwan	7.04
Paris	France	6.86
Toronto	**Canada**	**6.74**
Sao Paulo	Brazil	6.73
Oslo	Norway	6.55
Houston	United States	6.51
Bankok	Thailand	6.32
Singapore	Singapore	5.93
Sydney	Australia	5.89
Ottawa	**Canada**	**5.38**
Minneapolis	United States	4.92
Stockholm	Sweden	4.75
Calgary	**Canada**	**4.38**
Montreal	**Canada**	**4.32**
Portland	United States	3.95
Winnipeg	**Canada**	**3.91**
Vancouver	**Canada**	**3.68**
Seattle	United States	3.29

*Based on typical monthly billing demand of 1000 kW and energy consumption of 400 000 kWh. Tokyo is based on a monthly billing of 980 kW and energy consumption of 333 333 kWh.

Source: Canadian data were obtained from the Electricity Branch, Department of Natural Resources Canada. Data for other countries were obtained from a survey undertaken by the Electricity Branch, Department of Natural Resources Canada, February 1993.

Chapter 3

Regulatory Structures

Federal Regulation

The Constitutional Framework

Canada is a federal state. The power to make laws is divided between the federal government and the provincial governments. Each level of government has independent authority, set out in the *Constitution Act, 1867*, to make laws in certain areas. Within its own area of authority, each level of government is autonomous.

The *Constitution Act, 1867*, divides legislative power between the Parliament of Canada and provincial legislatures. It states that each legislative body may make laws relating to certain classes of subjects. This distribution of powers is listed in sections 91 and 92 of the Act, supplemented by section 92A, which was added in 1982.

Generally speaking, the classes of powers listed in sections 91 and 92 do not overlap: a particular class is assigned to either the Parliament of Canada or to the provinces but not to both. The *Constitution Act, 1867*, can be thought of as defining two mutually exclusive domains of legislative authority.

There are two important qualifications to this exclusivity: in certain areas concurrent powers are assigned to both levels of government, in other areas, each level may have authority to enact laws, based on its list of powers. If there is a direct conflict between the federal and provincial laws in either case, the federal law is paramount.

Energy is not specifically mentioned in sections 91 and 92, although it is referred to in section 92A. Laws that purport to regulate one or another aspect of energy production, transportation, and utilization thus derive their constitutional validity from two sources: (i) those parts of section 91 and 92 that are relevant to the specific energy activity in question, and (ii) section 92A, which deals specifically with natural resources and electrical energy.

Electricity generation systems mostly fall within provincial jurisdiction; they are "local works and undertakings" under section 92(10) of the *Constitution Act, 1867*. Section 92A(1)(c) reinforces this principle. It assigns to the provinces explicit responsibility for "sites and facilities in the province for the generation and production of electrical energy."

The only exception to the above is nuclear power. In 1946, with the passage of the *Atomic Energy Control Act,* the Canadian Parliament declared that all works and undertakings for the production, use and application of atomic energy are for the general advantage of Canada. The effect of this declaration was to place nuclear generation facilities within Canadian government jurisdiction, under sections 92(10)(c) and 91(29) of the *Constitution Act, 1867*. (Section 91(29) assigns to the Parliament of Canada all classes of subjects not exclusively assigned to the provinces. Section 92(10)(c) states that the provinces will not have jurisdiction over local works and undertakings declared by Parliament to be for the general advantage of Canada.)

Jurisdiction over international and interprovincial transmission systems derives from sections 92(10)(a) and 91(29). Section 92(10) assigns general responsibility for "local works and undertakings" to the provinces. It then goes on to list certain exceptions. One exception, stated in section 92(10)(a), is any work or undertaking connecting one province to another or extending beyond the limits of a province. Section 91(29) states that any class of subject not assigned exclusively to the provinces shall be within the power of the Canadian Parliament. Thus the effect of sections 92(10)(a) and 91(29) taken together is to confer upon the Parliament of

Canada exclusive legislative authority over transportation undertakings that cross interprovincial boundaries or the international boundary.

Provincial authority over interprovincial transmission systems derives from section 92(10), which allocates to the provinces authority over works and undertakings that are solely provincial in nature.

Section 91(2) confers upon the Parliament of Canada exclusive legislative authority on matters relating to "the regulation of trade and commerce." This is the primary basis upon which the Canadian government regulates electricity exports. Federal jurisdiction over electricity exports may also be derived from sections 92(10) and 91(29), which enable the Parliament of Canada to legislate with respect to international undertakings; this power extends to the marketing of the products transported by such undertakings.

With regard to the regulation of interprovincial electricity sales, the *Constitution Act, 1867* defines concurrent powers. Federal authority is derived principally from the trade and commerce power, section 91(2). Provincial authority derives from section 92A(2), which gives the provinces the power to make laws respecting the export of energy to other parts of Canada, provided that such laws do not discriminate with respect to price or to supply. If a conflict between federal and provincial laws over interprovincial trade should arise, the federal law will prevail. Federal paramountcy in this regard is explicitly stated in section 92A(3).

The above brief summary of the constitutional principles governing electricity in Canada indicates quite clearly that the powers of the Parliament of Canada, extensive though they may be on matters of trade, are quite limited insofar as electricity matters generally are concerned. The constitution assigns to the provinces exclusive jurisdiction over electricity matters that are wholly intraprovincial in nature, and it assigns to the provinces concurrent powers with respect to interprovincial trade. Furthermore, it is the ability of the provincial utilities to enter into purchase and sales agreements, combined with the electricity supply policies of the provincial governments, that primarily determine both the nature and the extent of Canadian electricity trade. The Canadian government, if it is to achieve policy objectives relating to electricity, can therefore achieve very little by acting unilaterally. First and foremost, it must seek provincial consensus and provincial cooperation.

Based on the above-mentioned constitutional framework, two federal regulatory agencies have been established to regulate electricity trade and nuclear energy. Environmental matters related to energy projects are handled by Environment Canada. Provincial regulatory agencies have also been established to implement regulation on electrical energy demand, supply, pricing, and environment assessment on power projects in the provinces.

National Energy Board

The National Energy Board (NEB) is a federal tribunal, created in 1959 by an Act of Parliament. The Board's powers and duties are derived from the *National Energy Board Act.* Under the Act, the Board advises the federal government on the development and use of energy resources, and regulates specific matters concerning oil, gas and electricity. The Board's jurisdiction over electrical matters is limited to the certification of international and designated interprovincial power lines and the licensing of electricity exports from Canada. The Board has no jurisdiction over imports of electricity.

On September 6, 1988, a new policy concerning the regulation of electricity exports and

international power lines was announced. Legislation amending the *NEB Act* to give effect to this policy (Bill C-23) was proclaimed on June 1, 1990.

Under the new policy, the Government of Canada will continue to authorize international power lines and exports of electricity. Such authorizations will be of two kinds: (i) permits, which will not require a public hearing or Governor in Council approval; or (ii) licenses (in the case of electricity exports) or certificates (in the case of power lines), which will require a public hearing and Governor in Council approval.

Authorizations will normally be by an NEB-issued permit unless the Governor in Council, on the advice of the Board, designates the application for certification or licensing. Designations are not likely to occur, except in cases where there is evidence that the export applicant has not taken into consideration (a) the effect of the exportation of the electricity on provinces other than that from which the electricity is to be exported; (b) the impact of the exportation on the environment; and (c) whether the applicant has offered electricity to be exported to domestic buyers under the same terms and conditions.

Once an application is designated, the Board will conduct a public hearing, and it will not issue a licence or certificate unless it is fully satisfied that the proposal is in the Canadian public interest. Licences and certificates will not be issued unless they are also approved by the Governor in Council.

Under the amendments to the *NEB Act*, Part III.1 provides for the federal regulation of international power lines. In determining whether to recommend to the Governor in Council designation of a power line, the Board will have regard to all relevant considerations, including: (i) the effect of the power line on other provinces; (ii) the impact of construction and operation of the power line on the environment; and (iii) any other matters that may be specified in the regulations.

In making its determination, the Board will seek to avoid the duplication of measures taken by the applicant and the relevant provincial government(s). The NEB will continue to authorize the general corridor through which an international power line will pass. However, the precise location of the line within this corridor will normally be determined by provincial regulatory procedures, and any expropriation that may be necessary will be done under provincial laws. The only exception to this general procedure will be in cases where the applicant elects to have federal law apply.

The Governor in Council may by order, designate a particular interprovincial power line for regulation in the same manner as international power lines. When power from one province simply enters the grid of another province, there is no federal regulation.

Part VI of the amended *NEB Act* includes a Division II, which provides for the regulation of electric power exports. The maximum duration of export licences and permits will be 30 years. In determining whether to recommend to the Governor in Council designation of an application for export, the board will have regard to all relevant considerations, including: (i) the effect of the export on provinces other than that from which the electricity is to be exported; (ii) whether those wishing to buy electricity for consumption in Canada have been granted fair market access to the electricity proposed for export; (iii) the impact of the export on the environment; and (iv) any other matters that may be specified in the regulations. In making its determination, the Board will also seek to avoid the duplication of measures taken by the applicant and the sponsoring provincial government.

Atomic Energy Control Board

Immediately after World War II, Canada began to study the question of how to encourage the use of nuclear energy for peaceful purposes. In 1946, Parliament passed the *Atomic Energy Control Act* with this objective in mind.

The Act gave the federal government control over the development, application and use of nuclear energy and established the Atomic Energy Control Board (AECB). The five-member Board administers and enforces the Act, from which it derives its authority to regulate the health, safety, security and environmental aspects of nuclear energy. The AECB reports to Parliament through a designated Minister, currently the Minister of Natural Resources Canada.

The Board's primary function is to license Canadian nuclear facilities and activities dealing with prescribed substances and equipment. Nuclear facilities include power and research reactors, uranium mines and refineries, fuel fabrication plants, heavy water plants, waste management facilities and particle accelerators. Prescribed substances include uranium, thorium, heavy water and radioisotopes. Activities relating to such substances, which may be licensed, include production, processing, sale, use, import and export. Before issuing a licence, the AECB ensures that the appropriate health, safety and security standards are met.

The AECB's control also extends to international security of nuclear materials and technology. Through the licensing process, it ensures that nuclear equipment and supplies are exported only in accordance with Canada's obligations under the Treaty on the Non-Proliferation of Nuclear Weapons.

Provincial Regulation

As noted above, under the Canadian Constitution the provinces have legislative authority over the generation, transmission and distribution of electricity. In most provinces some form of regulation exists, and most provinces have established regulatory bodies to oversee the utilities, although the degree of supervision varies. The major areas subject to review are rate-setting and the construction of new facilities. The nature of provincial regulation with respect to these matters is described briefly below. The environmental regulations of the provinces are described in Chapter 4.

Newfoundland

Newfoundland Light & Power Company (NLPC) and Newfoundland and Labrador Hydro (NLH) are regulated by the Newfoundland Board of Commissioners of Public Utilities. The Board fully regulates the rates and policies of NLPC, including the construction of new facilities. Since 1977, the Board has also had authority under the *Electric Power Control Act* to review NLH's rates for residential customers. The Board makes recommendations to the Newfoundland Cabinet, which is the final authority for utility rates.

Cabinet is also the final authority with respect to NLH's capital expenditure program. Proposals by NLH for new facilities must receive Cabinet approval before construction can begin. NLPC must receive the approval of the province's Board of Commissioners of Public Utilities before proceeding with the construction of new facilities.

Prince Edward Island

Maritime Electric Company Limited is regulated by the Island Regulatory and Appeals Commission of Prince Edward Island (formerly

the Public Utilities Commission of Prince Edward Island) under the provisions of the *Electric Power and Telephone Act.* The Commission has decision-making authority over electric utility rates in the province and screens all proposals for the construction of new generation and transmission facilities. If the Commission believes that a new facility may adversely affect the environment, a formal environmental assessment review process is initiated. A description of this process is provided in Chapter 4.

Nova Scotia

Since 1976, the Nova Scotia Board of Commissioners of Public Utilities, in accordance with the provincial *Public Utilities Act*, has had full decision-making power over the utility's rates and policies.

The Board's authority extends to the construction of new facilities, and utilities are required to apply directly to the Board when planning new generation or transmission facilities. As part of the review process, the Board holds public hearings, during which the utility presents its proposed project, costs and alternative plans. Members of the public may intervene directly during a hearing. The Board of Commissioners is the final authority on new facilities.

Nova Scotia Power Corporation was privatized in August 1992 changing its name to Nova Scotia Power Incorporated (NSPI). However, the Nova Scotia Public Utilities Board, in accordance with the *Public Utilities Act*, remains the final authority regarding NSPI's rates and development plans.

New Brunswick

As a Crown corporation, New Brunswick Power reports to the provincial government through its chairman, who is a member of the Cabinet. Rates and operations are regulated by a nine-member Board of Commissioners appointed by the Lieutenant Governor of New Brunswick. The utility's chairman and vice chairman sit on the Board. The Board's recommendations are referred to the provincial Cabinet, which is the final regulatory authority. A bi-partisan Crown corporation committee also reviews utility rates and operations annually.

NB Power must receive approval from Cabinet before proceeding with the construction of new facilities. Although Cabinet is the final authority in this regard, its decision is based upon a recommendation from the Minister of Municipal Affairs and Environment, following an evaluation of the project's possible environmental impacts. New Brunswick's environmental impact assessment process is described in Chapter 4.

Quebec

In Quebec, the National Assembly's committee on economics and employment reviews Hydro-Québec's long-term development plan, which includes any proposed rate changes. The committee then makes a recommendation to the Minister of Energy and Resources, who in turn makes a recommendation to Cabinet. Rate increases can therefore be implemented by Hydro-Québec only after they have been approved by Cabinet.

The construction of new facilities by Hydro-Québec can take place only after the utility has received an Order-in-Council from the provincial government. Before an Order is issued, the Department of the Environment and the Department of Energy and Resources must approve plans for the new facility. Other departments and agencies are also consulted.

Ontario

Ontario Hydro is a provincially owned corporation, which reports to the government through the Minister of Energy. The management of Ontario Hydro is under the direction and control of its Board of Directors. Proposed rate changes are referred to the Ontario Energy Board (OEB), through the Minister of Energy, for examination at public hearings. However, it is the Board of Ontario Hydro that is authorized to set the utility's rates, and it may accept or reject the recommendations of the OEB.

On matters concerning its generation expansion program and transmission facilities, Ontario Hydro is regulated by the provincial Joint Hearing Board. The Board is composed of members from the Environmental Assessment Board and the Ontario Municipal Board. The Joint Board makes a recommendation to the provincial government, and final approval must be given through an Order-in-Council.

Manitoba

Under the *Manitoba Crown Corporations Public Review and Accountability Act* of 1988, Manitoba Hydro's proposed changes to domestic rates must be reviewed by the Manitoba Public Utilities Board, which holds a public review and makes a final decision on the proposal.

Under the 1988 *Manitoba Environment Act*, the provincial government must also approve major facility construction. Applications are made to the Minister of the Environment and a full environmental assessment is required. A description of Manitoba's environmental assessment review process is given in Chapter 4.

Saskatchewan

Saskatchewan Power Corporation (SaskPower) is governed by a government-appointed Board of Directors that is responsible for the management and operation of the Crown utility. Proposals to increase rates or construct new generation or transmission facilities must be approved by the Board of Directors. The minister responsible for SaskPower is a member of the Board.

Alberta

TransAlta Utilities Corporation and Alberta Power Limited are investor-owned electric utilities in Alberta. They are regulated by the Alberta Energy Resources Conservation Board (ERCB) with respect to the development of generation and transmission facilities, coal mine developments and changes in service areas. Thermal generating stations are issued permits, which are subject to Lieutenant Governor in Council approval, while hydro dam approvals require final authorization through the passage of a bill in the legislature. TransAlta's and Alberta Power's rates are regulated by the Alberta Public Utilities Board, under the provisions of the *Public Utilities Board Act* of 1980.

As a municipally owned utility, Edmonton Power is subject to the authority of Edmonton Council, as well as the various provincial regulatory bodies. Its rates and financing are regulated by city council, while the ERCB is responsible for the regulation of new generation and transmission facilities.

The three utilities participate in the cost-pooling program of the Electric Energy Marketing Agency (EEMA). The EEMA was established in 1982 by the provincial government to help equalize power costs throughout Alberta. Under EEMA legislation, the utilities' generation and transmission costs are regulated by the Public

Utilities Board. The Board also approves the selling prices of electricity to EEMA, which then pools the utilities' costs and resells the power at average prices back to the utilities. In the Fall of 1991, the provincial government established a panel to review the equalization policy. The panel released a report on the status of the EEMA in February 1993, recommending that transfer payments be provided only when costs exceed EEMA average by 6 per cent.

British Columbia

Electricity rate changes in the province of British Columbia require the approval of the British Columbia Utilities Commission (BCUC). Major generation and transmission projects require the approval of the provincial Cabinet. Upon receiving an application to construct a major facility, the government may refer the application to the BCUC for review and a recommended course of action. Projects that obtain Cabinet approval receive an Energy Project Certificate from the province.

Yukon

The Yukon Energy Corporation and the Yukon Electrical Company are regulated by the Yukon Utility Board, under the *Public Utilities Act of 1986*. Under this Act, the Corporation and Company must file applications for rate changes or facility construction with the Board, which reviews the applications and makes a decision.

Northwest Territories

The Northwest Territories Power Corporation and Northland Utilities Enterprises Limited are regulated by the *Northwest Utilities Act* of 1989. Under the Act, they must file an application with the N.W.T. Public Utilities Board in order to receive authority for rate changes or facility development. Upon receiving an application, the Board holds a public hearing and then reaches a decision, which is final.

Electricity Regulatory Agencies

Canada:

- National Energy Board
- Atomic Energy Control Board

Provinces:

- Newfoundland Board of Commissioners of Public Utilities
- Nova Scotia Board of Commissioners of Public Utilities
- New Brunswick Board of Commissioners
- Quebec Legislative Assembly
- Ontario Energy Board (Rates)
- Ontario Joint Hearing Board (Generating & Transmission)
- Manitoba Public Utilities Board
- Saskatchewan Legislature
- Alberta Energy Resources Conservation Board (G&T Plans)
- Alberta Public Utilities Board (G&T Costs)
- Electrical Energy Marketing Agency (Prices)
- British Columbia Utilities Commission

Electricity and the Environment

Energy is the engine of economic growth. It is also a major source of pollution. The need to develop relatively inexpensive sources of energy as a basis for economic growth, and increasing public pressure to limit environmental damage, present a major challenge to governments and utilities. In Canada, the task of balancing energy requirements and environmental demands is being handled in a number of ways including environmental impact analyses, development and application of techniques to reduce emissions and long term shifts in the fuel mix used to generate power.

Most, if not all, energy generation and transmission projects have some impact on the environment. These range from chemicals contained in flue gases to the effect on plant and animal life when clearing a way for transmission lines. Not all of these impacts are necessarily harmful or permanent and some are even seen as beneficial. The most significant of these impacts are identified briefly as follows:

Impacts Attributable to Electricity Generation

Coal-Fired Generation

Roughly sixty per cent of the energy produced in coal combustion is in the form of waste heat emanating from either the stack or the cooling water. Flue gases include a number of chemicals including sulphur dioxide and nitrogen oxides (which are major components of acid precipitation), hydrocarbons (which combine with nitrogen oxides in the atmosphere to produce low-level ozone which - in high concentrations - can harm certain crops) and carbon dioxide which may contribute to higher global mean temperatures. Other by-products of coal combustion include contaminated solid wastes and process waters.

Oil-Fired Generation

Oil-fired generation is generally considered to be less harmful than coal-fired because sulphur is removed from the oil during the refining process. However, exhaust gases still contribute carbon monoxide, sulphur dioxide, nitrogen oxide, hydrocarbons and carbon dioxide to the atmosphere.

Natural Gas Fired Generation

Hydrogen sulphide is removed from natural gas before shipment so that the principal by-products of combustion are carbon dioxide and water.

Hydro-Electric Generation

Environmental impacts result from dam construction at the reservoir site as well as downstream. These include the effect on the local climate, vegetation, fish and wild life caused by the creation or expansion of a reservoir and the construction of a dam and generating station. Water levels and flows are affected above and below the dam as are the nutrient content and temperatures of water bodies. Some of these impacts could be positive, including the reduction of seasonal flooding and the creation of possible new wild life reserves.

Nuclear Generation

Unlike the combustion of fossil fuels, nuclear generation does not produce any significant amounts of gaseous emissions. Indeed, environment impact is one area where nuclear energy may have a significant advantage. Nevertheless, safety and the management of radioactive wastes pose a challenge to the nuclear industry, both technically and in terms of public acceptance.

Impacts Attributable to Electricity Transmission

Construction of Transmission Lines

Many of the effects caused by line construction are temporary, including the disruption of wild and aquatic life, as well as noise and air pollution. However, where vegetation is cleared to make a right of way, local soil erosion and increased sedimentation of water bodies can result.

Operation and Maintenance of Transmission Lines

Plant and wild life along the right of way can be affected by herbicide application and cut-backs of vegetation. Other underground installations (such as a pipeline) might also be damaged due to the operation of a ground electrode and studies are currently underway to determine whether the lines' extra low frequency electromagnetic fields are a danger to health.

Other Possible Contaminants

Polychlorinated Biphenyls (PCBs).

Because of their excellent insulating and thermal properties, PCBs are used in electrical equipment insulating oils. Current evidence suggests that there is no positive link between work place exposure to PCBs (as such) and the likelihood of contracting cancer. However, when involved in transformer or capacitor fires, PCBs release highly toxic substances called polychlorinated dibenzofurans (PCDF).

Acid Rain

Acid rain or acid precipitation, is the term given to the rain, snow, sleet, hail, frost or dew which contain sulphuric and nitric acids. Such acids can come from the atmospheric conversion of sulphur and nitrogen oxide (SO_x and NO_x) emissions. Around the world, up to half of the sulphur in the air comes from natural sources such as rotting vegetation, plankton, and in some places, volcanoes.

However, the principal sources of sulphur oxide emissions in North America are coal-fired power generating stations and non-ferrous ore (i.e., nickel, copper, lead and zinc) smelters. Coal-fired generating stations are the main source of sulphur emissions in the U.S., whereas in Canada 60 per cent come from smelters. The main source of nitrogen oxide emissions in both countries are vehicle exhausts.

U.S. emissions exceed Canadian by a factor of 5 for sulphur oxide and 10 for nitrogen oxide, but both countries contribute to each others problems through long-range atmospheric transportation of airborne pollutants. It is estimated that 80-90 per cent of the acid rain affecting Canada is attributable pollutants originating in the U.S.

The Greenhouse Effect

Life is possible on earth because of the existence in the atmosphere of a number of important gases, including carbon dioxide (CO_2), nitrous oxide (N_2O),ozone (O_3) and methane (CH_4). These gases behave as an insulating blanket, absorbing much of the heat escaping from the earth's surface and thereby trapping warmth within the lower atmosphere. This "greenhouse effect" is a natural phenomenon without which the earth's surface would be 30 degrees celsius colder, and uninhabitable to most existing life forms.

The issue is the relatively rapid increase in the build up of these greenhouse gases primarily as a result of the burning of fossil fuels and other industrial and agricultural processes, and the

effect some scientists believe this will have on global temperatures and, ultimately, on the world's climate and ocean levels.

Burning of fossil fuels (coal, oil and natural gas) to produce energy releases carbon dioxide and nitrous oxide into the atmosphere and also contributes to increased levels of surface ozone.

The most significant of these greenhouse gases is carbon dioxide. Since 1860, atmospheric CO_2 concentrations have risen from 270-290 ppmv (parts per million by volume) to nearly 350 ppmv today. Projections of CO_2 trends are subject to large uncertainties, but many scientists believe that concentrations of this and other greenhouse gases could double by the middle of the next century.

Responses to Environmental Impact of Electricity Generation and Transmission

A number of measures have been implemented by governments and industry to monitor and reduce the environmental impacts of electricity generation and transmission. These include the employment of technologies, fuel mix changes, studies and the development and application of government policies, standards, codes of practice and regulations. The most important of these are identified briefly in this summary and in more detail in separate notes.

Technological Measures

These measures are often introduced in response to government regulations and standards. Many are designed to reduce sulphur and nitrous oxide emissions (major contributors to acid precipitation) and include a number of flue gas desulphurization technologies, circulating fluidized bed combustion, low nitrous oxide burners, coal blending and cleaning and co-generation.

Switch to Environmentally More Benign Fuels

Although all methods of generating energy have an impact on the environment, some are considered to be less harmful than others. A decline in the relative importance of thermal generation (by fossil fuels - coal, oil and natural gas) and an increase in that of hydro and nuclear will reduce the emission of atmospheric pollutants, even where fossil fuel plants have been fitted with emission controls. The experience in Canada is mixed: the relative importance of fossil fuels declined from 23 per cent in 1970 to 17 per cent in 1987 but as total electricity generation more than doubled over this same period, there was an actual growth in thermal generation (from 47 to 78 terawatt hours) over this same period with a real decline only being registered in the last few years. Again, although the actual amount of hydro-electric power generated doubled between 1970 and 1987, its relative importance declined from 77 per cent to 66 per cent, while that of nuclear rose from under 1 per cent to 17 per cent.

Studies

Methodologically sound studies can play a major role in establishing the existence and nature of environmental impacts and are therefore a necessary first stage in the response. A number of current studies focus on determining whether or not some link exists between extra low frequency electromagnetic fields and various forms of cancer. The most interesting of these studies include one financed by Ontario Hydro, Hydro-Québec and Electricité de France and another by the U.S. Electric Power Research Institute. Other important areas of study focus on PCBs, acid rain and the so-called "Greenhouse Effect". Another interesting study entitled "Project 88: Harnessing Market Forces to Protect our Environment: Initiatives for the New President," was produced by a team of experts and sponsored by Senators Wirth

(Democrat-Colorado) and Heinz (Republican-Pennsylvania). This study focuses on economic tools that might be used to solve environmental problems relating to energy, climate change, land use and resource management.

Setting Emission Targets

The most important of these is the federal government's agreement with seven provincial governments to set limits on sulphur oxide emissions, which should result in a 50 per cent reduction by 1994 when compared to a 1980 base. Canada is also a signatory of the 1979 Helsinki Protocol on Sulphur Dioxide thereby agreeing to reduce transboundary emissions by 30 per cent by 1993 when compared to a 1980 base.

Concern with the effects of acid rain and the fact that important constituents of it can be carried in the atmosphere for considerable distances, has led to the establishment of emission limits and the development of transboundary emission accords.

In March 1985, the Canadian government announced a comprehensive program involving working with provincial governments and industry to reduce sulphur oxide emissions by 50 per cent by 1994 when compared to a 1980 base. As control of such emissions lie principally within provincial jurisdiction, it was necessary for all seven provinces involved to enter into a federal-provincial agreement to give effect to the overall target. This was done in December 1987, when the last of the seven provinces, Nova Scotia, signed the agreement with the federal government.

The sulphur oxide emission reduction targets for 1994 are set out in Table 4.1.

Environmental Assessment Review Processes

As was pointed out earlier, electricity generation and transmission projects have some impacts on the environment. Governments, industry and other groups in society have recognized the need to assess and reduce these impacts. For their part, federal and provincial governments have established processes that are designed to reduce the environmental consequences of electrical generation and transmission.

Despite differences from one province to another in the nature of the environment and in the scale and type of project proposed, there are some similarities in the processes developed by the various provincial governments to ensure that the development of electricity generation and transmission projects does minimum damage to the environment.

In most provinces, the proponent (a person, company, provincial agency or Crown corporation) is responsible for conducting an environmental assessment of activities. A lead agency (often in the department responsible for the environment) is normally appointed to review this assessment on behalf of the provincial government.

In all 10 provinces, decision-making occurs in discrete steps. Small, routine projects with no significant impacts are first screened out and allowed to proceed with a minimum loss of time and expense. Projects that may adversely affect the environment are submitted for a more detailed (and sometimes more visible and structured) review. Such projects could be subject to public review by an independent board or panel.

The Environmental Impact Statement (EIS) is used in most provinces and by the federal government to assess projects that may have a major adverse environmental impact. The EIS

format is similar in all jurisdictions and involves (i) a project description, (ii) an analysis of how the project will affect the environment, and (iii) a description of proposed measures to reduce environmental impacts. It is normally prepared by the project proponent and is reviewed by the lead and other government agencies or by a public review board or panel.

The EIS process usually involves some form of public review, but the degree of formality varies among provinces, from formal legal procedures to informal community meetings. At both the federal and provincial levels, the final decision-maker is usually an elected official or officials -- a Cabinet minister or the entire Cabinet. This is the same as in the power regulation processes stated in Chapter 3.

The processes in place in Canadian jurisdictions are outlined below. Some of this material is reviewed in more detail in a report prepared by the Canadian Council of Ministers of the Environment (CCME).[1] Since this 1985 report was completed, British Columbia, Saskatchewan, Manitoba, New Brunswick, Prince Edward Island, and Newfoundland have introduced major changes, and these are reflected in this chapter. In addition, an Environmental Assessment Act was passed in Nova Scotia in 1988 and was proclaimed in July 1989. Alberta's Environmental Protection and Enhancement Act was passed in the summer of 1992 and went into effect September 1, 1993.

Federal Process

The Federal Government's Environmental Assessment Review Process

In December 1973, Cabinet established the federal Environmental Assessment Review Process (EARP) to ensure that the environmental effects of all federal proposals are assessed early in the planning process. A federal proposal is one initiated by a federal agency, or one that involves federal funding, federal property, or affects an area of federal responsibility. Federal Crown corporations are not bound by the Cabinet decision, but they are invited to participate in the process.

Under EARP, federal departments are responsible for assessing their own proposals. They conduct an initial screening to determine whether a given proposal will have significant environmental effects. If no such effects are perceived, the project may go ahead with appropriate monitoring by the initiating department. The results of all such decisions are published in summary form.

If potentially significant environmental effects are perceived, a formal review process is undertaken by an Environmental Assessment Panel created by the Minister of the Environment. The Panel is assisted in its work by the Federal Environmental Assessment Review Office. The Panel normally requires that the sponsor of the proposal prepare an EIS. If the Minister of the Environment and the initiating minister concur, the scope of the Panel may be broadened to include general socioeconomic effects and the need for the project.

Public participation is an integral part of the assessment process. Any person or organization with an interest in the proposal is provided with an opportunity to appear before the Panel.

[1] William J. Couch, Ph.D. (ed), *Environmental Assessment in Canada: 1985 Summary of Current Practice in Canada.* (Ottawa, Canadian Council of Resource and Environment Ministers, 1985, catalogue number EN 104-4/1985.)

Once a Panel has completed its deliberations and evaluated all information on a proposal, it prepares a report containing its findings and recommendations. A Panel could recommend that a proposal not proceed, that it proceed as planned, or that it proceed subject to certain terms and conditions. The recommendations are submitted to the Minister of the Environment and the initiating minister, who must decide (i) to whom the recommendations are directed, (ii) to what extent they should be incorporated into terms and conditions governing the project, and (iii) in what manner they are to be made public. In the event of a disagreement between the two ministers, the question may be submitted to Cabinet.

Following the publication of a green paper in 1987 that identified a number of possible changes to the EARP process[2], the Federal Environmental Assessment Review Office (FEARO) has carried out extensive consultations with the public, and federal departments and agencies. Bill C-78, introducing a new Canadian Environmental Assessment Act (CEAA), was tabled in the House of Commons on June 18, 1990, and was discussed but not concluded in the 1990 session. Bill C-78 was reintroduced as Bill C-13 in the House of Commons on May 29, 1991. Bill C-13 was passed by both House and Senate. The CEAA received Royal Assent in June 1992, however, proclamation was delayed until four key regulations could be prepared. These are:

- the Law List - a list of statutes that trigger a Federal environmental assessment;
- the Comprehensive Study List - a list of projects considered important enough to warrant a mandatory detailed study;
- the Inclusion List - a list of activities that require assessment; and
- the Exclusion List - a list of projects that are excluded from assessment.

The regulations have been developed in consultation with a Regulatory Advisory Committee (RAC), established by FEARO. Industry representatives on the RAC included the Mining Association of Canada, the Canadian Association of Petroleum Producers, the Canadian Electrical Association, the Canadian Nuclear Association, the Canadian Pulp and Paper Association, and environmental groups as well as native groups.

Over a period of 16 months, the RAC attempted to reach consensus on the regulations. In the end, consensus was reached on some provisions but many remained highly contentious. The proclamation of CEAA is anticipated in late 1993. At that time, the Federal Environmental Assessment Review Office will be replaced by the Canadian Environmental Assessment Agency.

Provincial Processes

British Columbia

The principal legal basis for British Columbia's energy project review process is the Utilities Commission Act, 1980. Major energy projects cannot proceed until the proponent has received approval by means of an Energy Project Certificate, a Ministers' Order, or a Certificate of Public Convenience and Necessity, all of which set out the terms and conditions under which the facility may be constructed and operated.

In order to obtain approval for a project, a proponent must provide a prospectus and then an application to the Ministry of Energy, Mines and Petroleum Resources, which in turn refers

[2] Environment Canada, *Reforming Environmental Assessment: A Discussion Paper.* (Ottawa, Minister of Supply and Services Canada 1987, catalogue number EN 106-5/1987.)

them to an Energy Project Coordinating Committee (EPCC). This steering group is chaired by the Ministry of Energy, Mines and Petroleum Resources, and includes representatives from the Ministry of Environment, the British Columbia Utilities Commission (BCUC), and FEARO.

In the application, the proponent must address, among other items, environmental impacts; impact management strategies; benefit and costs; and proposals for compensation, mitigation and monitoring. The EPCC, through three inter-ministry working groups, reviews the material and submits its recommendations to the ministers of Environment and Energy, Mines and Petroleum Resources. Generally, the recommendations are either for a public hearing by the BCUC or exemption from provisions of the Utilities Commission Act. The application may also be rejected if it fails to satisfy public interest criteria.

If an application is referred to the BCUC, once the public hearing is completed, a report is sent to the two ministers for consideration by Cabinet. The Minister of Energy, Mines and Petroleum Resources, with the concurrence of the Minister of Environment, then announces the Cabinet decision.

If a public utility applies for an Energy Project Certificate, the ministers may refer the application to the BCUC for review and a decision. This may include holding a public hearing and may result in the issuance, directly by the Commission, of a Certificate of Public Convenience and Necessity.

Environmental review in British Columbia presently includes three processes: energy, mines, and major industrial projects such as pulp and paper. The government intends to draft a new bill to consolidate these three processes into one. The bill is now under preparation and will be introduced to the Legislature this year.

Alberta

Alberta's Environmental Impact Assessment (EIA) process was established by the Land Surface Conservation and Reclamation Act of 1973. Pursuant to Section 8 of the Act, the Minister of the Environment may require the proponent of a proposed development to prepare an EIA report if he or she believes it is in the public interest to do so. The purpose of an EIA is to provide information to the public and the government to enable early identification and resolution of significant adverse effects on the environment.

The Alberta EIA process is implemented in accordance with the Alberta EIA Guidelines and administered by the Alberta Department of Environment. Most major resource developments proposed in Alberta are subject to this requirement. Major thermal and hydro generation projects require an EIA, and proponents of smaller projects must submit the environmental information necessary for the required approvals. In preparing an EIA, the proponent must consult with the public and provide opportunities for the public to participate in the preparation and review of the EIA.

Energy projects require the approval of the Alberta Energy Resources Conservation Board (ERCB) and Alberta Environment. Consequently, Alberta Environment and the ERCB coordinate their respective information requirements and reviews of energy projects. EIAs on energy projects are filed with Alberta Environment and the ERCB as part of the application to the ERCB. The ERCB may require a public hearing to be held for a project. After the ERCB makes its decision, Alberta Environment issues detailed environmental permits and licences.

Following three years of extensive public consultation, Alberta's Environmental Protection and Enhancement Act was passed and proclaimed on September 1, 1993. Highlights of the legislation and the new regulations include provisions to establish a legislated environmental impact assessment process, increase public consultation and participation, and allow more public access to information on proposed developments which may impact the environment.

Saskatchewan

The Environment Assessment Act of 1980 requires environmental impact assessments to be completed for major development projects. Exemptions may be granted by Cabinet only in cases of emergency.

The province's environmental impact assessment and review process is administered by the Saskatchewan Department of Environment and Resources Management (formerly Department of Environment and Public Safety), and projects may proceed only with the approval of the Minister. Proposals are screened by the department to determine whether the Act applies to a project and, if so, the nature and scope of the EIA. If it is determined that an EIA is not required, the project may proceed subject to all other statutory requirements.

Where an EIA is required, proponents are encouraged to undertake a public participation program as early as possible so that public comments and recommendations may be considered during the preparation of the Environmental Impact Statement (EIS). Further safeguards are built into the process, such as a minimum 30-day public review of the EIS and the power given to the Minister to require a public information meeting to be conducted and/or appoint a board of inquiry. The final decision to approve (with or without conditions) or to refuse the proposed development rests with the Minister. The government intends to reform the current environmental review process in the coming year.

Manitoba

The Manitoba Environment Act of 1988 replaces the former Clean Environment Act of 1968 and the Environmental Assessment and Review Process, adopted as provincial Cabinet policy in 1975.

The Act ensures that any person or organization undertaking a development specified in the regulations is required to file a Proposal with the Department of Environment at an early stage in the planning schedule. Other developments of environmental consequence are governed by regulations setting standards for environmental protection.

Developments are classified according to their potential environmental impact. Class 1 developments are any activities discharging pollutants. Class 2 developments are any activities with significant environmental impact caused by factors in addition to pollution, such as transportation and transmission facilities. Class 3 developments involve large-scale projects such as major hydroelectric developments.

Every submission for a development must be filed at a public registry. Once a proposal is filed, the Department of Environment is required to invite publicly written comments on the proposal. For more complex proposals, study guidelines are developed to assist proponents in preparing environmental assessments. Both the guidelines and the completed assessment are made available to the public for review.

Public meetings hosted by the proponent or public hearings by the Manitoba Clean Environment Commission, or both, may be held as part of the assessment and review process.

The Commission's role is to provide advice and recommendations to the Minister and to develop and maintain public participation in environmental matters.

The final product of the process is an environmental licence with terms and conditions specific to the proposal. Alternatively, a licence to proceed could be refused on the grounds of unacceptable environmental damage.

Ontario

The Minister of the Environment is responsible for the administration of the Environmental Assessment Act, which promotes improved planning by involving government ministries and agencies and the public in the environmental assessment, planning and approval process. (The environmental process in Ontario is also subject to the terms of the Consolidated Hearings Act, 1981. Details of the Consolidated Hearings Act may be obtained from *Environmental Assessment in Canada*[3], or from the October 1987 issue of *Canadian Environmental Law Reports.*[4] The environmental assessment process in Ontario is currently being reviewed by the government. Amendments to the Environmental Assessment Act are expected to be proposed in the very near future.

The Environment Minister may, with the approval of Cabinet, exempt proponents from the application of the Environmental Assessment Act, which currently applies to the activities of provincial ministries, municipalities and conservation authorities. Only those projects of the private sector designated by regulation are subject to the Act. Proponents planning a project must determine if the Act applies; where it does not apply; or where an exemption has been granted, the activity may proceed. If the Act applies, the proponent must prepare an Environmental Assessment (EA), which is reviewed by the Ministry of Environment and other interested provincial and federal government organizations.

The Ministry subsequently prepares a Government Review which, together with the EA, is released for a minimum 30-day public review. A hearing of the Environmental Assessment Board may then be requested by the reviewers, the public or the proponent. The Minister -- with the concurrence of Cabinet -- will make a decision whether to accept the EA, and whether to approve the undertaking, with or without conditions. The Minister may refer the decision to accept the EA, or the decision to approve the undertaking, or both, to a Board hearing. When the Minister decides to refer the matter to a Board hearing, the Board must give reasonable notice of the hearing, which is open to the public. The Minister or Cabinet has 28 days to make any amendments to the Board's decision; if no amendments are made within this period, the Board's decision becomes binding.

Quebec

In Quebec, the process of environmental assessment varies depending on whether a project is in the south of the province or in a territory that is the subject of agreements with native people.

The 1972 Environment Quality Act was amended significantly in 1978 to include an environmental impact assessment and review procedure. By regulation, this procedure applies essentially to projects in the south of the province. When a project is subject to the procedure, the proponent must submit an EIA to the Department of the Environment for an admissibility analysis and an evaluation of the environmental acceptability of the project. All

3 William J. Couch, Ph.D., op. cit.
4 *Canadian Environmental Law Reports*, New Series, Vol. 1, Part 6, October 1987.

projects are subject to a public consultation period, during which any citizen may ask the Minister of the Environment to hold a public hearing. Citizens can thus voice their views before the project is referred to Cabinet for acceptance or refusal. A new Act modifying the environmental evaluation process was passed in 1992. It will come into effect as soon as the government adopts secondary legislation.

In the northern Quebec territories, the provincial government has implemented two procedures to assess and review the environmental and social impacts of a given project. The first procedure is applicable to the James Bay region (between the 49th and 55th parallels). A feature of this procedure is the use of committees on which native people are always represented. These committees advise the Minister of the Environment throughout the various stages of the authorization process. North of the 55th parallel, the Kativik Environmental Quality Commission is in charge of reviewing the impact assessment study and has decision-making authority. These procedures, which were incorporated into the Environment Quality Act, stemmed from the James Bay and Northern Quebec Agreement (1975) and the Northeastern Quebec Agreement (1978).

New Brunswick

New Brunswick's Regulation on Environmental Impact Assessment came into effect in July 1987, to provide a legislative framework for environmental planning, including opportunities for public involvement. The Regulation, which replaced the province's 1975 Policy on Environmental Assessment, is designed to identify the environmental impacts associated with development proposals, before their implementation.

Under the Regulation, individuals, companies or public agencies proposing certain types of projects (for example, all electric power generating facilities with a production rating of three MW or more, and all electric power transmission lines exceeding sixty-nine kV in capacity or five km in length) are required to register information about the project with the Minister of Environment, at an early stage in the planning cycle. The Minister then screens the proposal to determine whether it is likely to have significant environmental impacts, including socioeconomic and biophysical effects.
If it appears that the project's impacts are likely to be significant, the Minister will inform the proponent that an EIA is required, and staff from the Department of Environment will work with the proponent in preparing initial draft guidelines for the EIA Study. A Review Committee, consisting of technical specialists from government agencies potentially affected by the proposal, is appointed by the Minister to formulate draft guidelines for the Study. These draft guidelines, which identify the important environmental issues to be addressed, must then be issued by the Minister for public comment, and any interested party may provide written comments to the Minister.

The principal objective of the EIA Study is to predict the project's impacts, should it proceed. Information gathered during the study is compiled in a draft Environmental Impact Assessment Report, which is then carefully examined by the Review Committee. If, on the advice of the Committee, the Minister is satisfied that the report adequately addresses all aspects of the guidelines, a second and more comprehensive opportunity for public involvement begins. A summary of the report, comments of the Review Committee, and full copies of the final report are released for public review and comment.

A public meeting to discuss the EIA takes place. Thereafter, the Minister reviews the study and public comments, and then recommends to the Lieutenant-Governor in Council whether or not the project should proceed.

A proposal to revise the current environmental impact assessment regulation is being prepared by the Department of Environment. The proposal is now soliciting comments from within government departments and will go to the public for input in the fall 1993. A new bill is likely to be recommended to the New Brunswick Legislature in the spring of 1994.

Nova Scotia

The current legal basis for environmental impact assessment in Nova Scotia is the Environmental Assessment Act. The Nova Scotia Department of the Environment (NSDOE), in consultation with other government agencies, is responsible for screening all projects submitted and advising the Minister on those that may have a significant and adverse environmental impact. After reviewing NSDOE's advice, as well as any public concern expressed, the Minister decides whether a project requires an Environmental Assessment (EA) Report. Where it is decided one is required, the proponent prepares a draft Report in response to guidelines and submits it to NSDOE. The department, other interested provincial and federal agencies, and the public, review the EA Report. NSDOE then recommends to the Minister whether the project should be approved, with or without conditions, or refused.

The public is invited to participate in the review process by providing comments when a project is submitted to the NSDOE, when study guidelines are issued, and when the EA Report is released. The Minister, taking into consideration NSDOE's recommendations and the views of the public, decides whether the project should proceed and, if so, under what conditions.

The Department of Environment is now undertaking comprehensive legislative review and consolidation of all environmental acts (14) and regulations (44). A proposed new Nova Scotia Environment Act will be released for public consultation in October 1993. This new Act will be introduced to the Legislature in the spring of 1994.

Prince Edward Island

The Environmental Protection Act of 1988 provides the overall legal authority for the environmental assessment process. It requires that any person who wishes to initiate a project must file a written proposal with the Department of Environmental Resources (formerly Department of Environment) and obtain written approval from the Minister to proceed.

With respect to utilities, the process is set out in the Electric Power and Telephone Act, which authorizes the Public Utilities Commission to issue project-specific guidelines to the proponent for the preparation of an EIS, if it believes that the project may adversely affect the environment. A copy of the EIS is then sent by the Commission to the Executive Council for its consideration. The Council may make a decision on the evidence available, or it may determine that the public interest requires public hearings to be held in the locality affected by the project. After the public hearings, the Commission examines the evidence and issues its findings to the Executive Council.

Newfoundland

The province's environmental assessment process operates under the authority of the Environmental Assessment Act of 1980, which is administered by the Department of Environment and Lands.

Any project that may have a significant adverse environmental impact must be registered with the Minister of Environment and Lands. After public and interdepartmental reviews of the registration document, the Minister, on the advice of the department, decides whether or

not an EIS is required. If an EIS is not required, the project may proceed subject to other relevant acts or regulations.

Where the Minister, on the advice of the Department, decides that an EIS may be required, an Environmental Preview Report (EPR) can be ordered. The EPR is prepared by the proponent and is available for public review and comment. Upon examination of the EPR, the Minister decides whether an EIS is required. If one is not required, the project may proceed subject to other relevant acts or regulations.

Where an EIS is required, it is prepared by the proponent; the Minister then makes it available for public review and comment. Should strong public interest be expressed, the Minister may recommend to Cabinet that an Environmental Assessment Board be appointed to conduct public hearings. The Minister makes the Board's report public, delivers copies to Cabinet, and subsequently recommends to Cabinet whether the project should be permitted to proceed, with or without conditions, or whether permission should be refused.

Like some of the other provinces, the Government of Newfoundland is now carrying out an internal study on its environmental review process. The government intends to modify or change the existing acts or regulations during the coming year.

Table 4.1 is on the following page.

Tables & Figures

Table 4.1
Sulphur Oxide Emission Reduction Targets, 1994

Province	Base Case (tonnes)	Reductions (tonnes)	% Objectives	Emissions (tonnes)
Manitoba	738 000	188 000	25.5	550 000
Ontario	2 194 000	1 529 000	69.7	665 000
Quebec	1 085 000	485 000	44.7	600 000
New Brunswick	215 000	30 000	14.0	185 000
P.E.I.	6 000	1 000	16.7	5 000
Nova Scotia	219 000	15 000	6.8	204 000
Newfoundland	59 000	14 000	23.7	45 000
Total	4 516 000	2 262 000	50.0	2 254 000

Source: Department of Natural Resources Canada

Electricity Consumption

Electricity and Primary and Secondary Energy

Electricity constitutes a significant market share of Canada's primary and secondary energy consumption. The contribution of electricity to total primary energy consumption* has steadily increased from 14 per cent in 1960 to 31 per cent in 1992, as shown in Figure 5.1. In terms of volume, primary energy consumption delivered in the form of electricity increased from 463 PJ in 1960 to 2559 PJ in 1992, an average annual growth of 5.5 per cent. This is more than double the average annual growth of non-electric primary energy consumption of 2.2 per cent registered for the same period. (Since 1990, the International Energy Agency (IEA) has agreed that hydro should be converted at 3.6 rather than 10.5 megajoules per kilowatt hour for the primary energy form).

Electricity constitutes a much smaller market share of secondary energy consumption* than primary energy consumption because of losses. Figure 5.2 indicates that electricity's share of Canadian secondary energy consumption was 11 per cent in 1960, and 25 per cent in 1992. The consumption growth rate for electricity was estimated to be 5.3 per cent during the period 1960-92, compared with non-electric secondary energy consumption of 2.1 per cent.

Total Electricity Consumption

In planning an electrical system, total electricity consumption (demand) must be determined first, followed by what type of energy and capacity mix is required to meet this demand. Total electricity consumption in a given country, region, or area normally includes generation by electric utilities, generation by industrial establishments, and net imports (imports minus exports).

Canada's total electricity consumption has experienced two distinct periods over the past 32 years: the first period was one of high growth from 1960 to 1974, followed by a period of low growth from 1975 to 1992. The abrupt change coincided with the first oil crisis of 1973-74, following which consumption growth rates in the ten provinces and two territories shrunk significantly. This dramatic reduction in electricity consumption growth was mainly attributed to reduced economic growth, high energy prices and energy conservation efforts. As indicated in Table 5.1, average annual growth rate of Canadian electricity consumption during the period 1960-74 was 6.6 per cent, compared with only 3.5 per cent for the period 1975-92.

Canadian electricity consumption rose only 0.9 per cent in 1992 because of slow economic growth. The real Gross Domestic Product grew 0.7 per cent in 1992, recovering from a negative growth of 1.7 per cent in 1991. Mild weather and energy conservation resulting from the implementation of demand-side management were the other factors contributing to low domestic electricity consumption.

Ontario was the only province that experienced consecutive negative electricity demand growth in 1990, 1991, and 1992. This occurred largely because of economic recession, mild weather, energy conservation efforts in the province, and rate increases.

Although its market share has been declining, the industrial sector is still the major user of electricity in Canada. Of the total electricity consumed in 1992, it is estimated that about 41 per cent was consumed in the industrial

** For definition, please see appendix on **Definitions and Abbreviations.***

sector, 29 per cent in the residential sector, 23 per cent in the commercial sector, and 7 per cent in transmission and distribution losses.

Since 1960, commercial sector energy consumption growth has been remarkable, averaging 7.0 per cent annually, compared with 6.1 per cent for the residential sector, and only 3.4 per cent for the industrial sector. Transmission and distribution losses have been reduced steadily since 1960 partly due to improvements of transmission technology.

Table 5.3 shows electricity flows in Canada. Quebec was the largest producing and consuming province, accounting for 29 per cent of Canada's total production and about 35 per cent of total consumption. Ontario was second with 28 per cent of production share and 29 per cent of consumption share. British Columbia was in the third place, with 13 per cent in production and 12 per cent in consumption shares.

Per Capita Electricity Consumption

As in the case of total consumption, per capita electricity consumption in Canada exhibited high and low growth patterns before and after the oil crisis of 1973-74. For the period 1960-92, Saskatchewan had the highest annual per capita growth in electricity consumption, averaging 6.9 per cent, followed by Prince Edward Island with 6.6 per cent, and New Brunswick and Alberta with 6.1 per cent each. High per capita electricity consumption in Saskatchewan was due to a slow population growth. During the past 32 years, Saskatchewan's growth rate was 0.3 per cent compared to the national average of 1.3%. In fact, Saskatchewan's population has been declining since 1988.

In 1992, Quebec was the largest electricity user in Canada with 23 770 kWh per person, about 37 per cent higher than the national average. This high electricity use is attributed to relatively low electricity prices and a high percentage of households (about 68 per cent) using electricity for space heating. In comparison, Prince Edward Island was the smallest electricity user in Canada with 5893 kWh (only about 34 per cent of the national average). Prince Edward Island has the highest electricity prices of the ten provinces and does not use electricity for household space heating. A great majority of households in Prince Edward Island use oil for space heating.

Household Characteristics and Facilities

As was pointed out earlier, electricity consumption in the residential sector has steadily increased, from a 19 per cent market share in 1960 to 29 per cent in 1992. In addition to economic factors, changes in household characteristics and household facilities and equipment also have considerable impact on residential electricity consumption. Table 5.5 summarizes household characteristics and facilities by province for 1992.

During the past 17 years, the number of households in Canada has increased from 6.9 million in 1976 to 10.1 million in 1992, a net increase of 3.2 million. However, the average number of persons per household has declined from 3.15 to 2.63 over the same period.

The use of electricity for space heating, mainly in the provinces of Quebec and New Brunswick, has steadily increased from 13 per cent of total households in 1976 to 34 per cent by 1992; the number of air conditioners from 13 per cent to 27 per cent; and automatic dishwashers from 19 per cent to 44 per cent. The use of electric washing machines also increased slightly over the same period, from 76 per cent to 79 per cent, while the use of electric clothes dryers increased significantly from 51 per cent to

74 per cent. By the end of 1992, households equipped with refrigerators and colour TV sets in Canada reached 99 and 98 per cent respectively.

Economic Growth and Electricity Consumption

Electricity consumption is affected by many factors: economic activity, demographic variables, electricity prices, other energy prices, conservation, policy changes, technological changes and weather. However, aggregate economic activity [as measured by the Gross Domestic Product (GDP)] is the most important variable. The historical relationship between per capita GDP and per capita electricity consumption is shown in Figure 5.4. Although the historical relationship between national economic growth and electricity consumption was dislocated between 1979 and 1983 (because of the second oil crisis of 1979 and the 1982 recession - the worst recession since WWII), it has reappeared since 1984.

Peak Demand

Peak demand is the annual maximum average kilowatt load of one hour duration within an electrical system. All electrical systems in Canada are peak in the winter. Table 5.8 reports the day in the winter which had the highest one-hour demand for each province over the 1992-93 period. For Canada as a whole, peak demand grew from 17 264 MW in 1960 to 82 836 MW in 1992 (Table 5.6), an average annual growth rate of 5.0 per cent. In comparison, total electricity consumption during the same period grew at an average of 4.7 per cent.

In 1992, peak demand shrunk 0.2 per cent because of economic recession and warm weather. (Prior to 1987, *Electric Power in Canada* reported peak demand for the calendar year. However, beginning in 1987, calendar-year peak was replaced by winter peak - November to February. This change was made in order to make our reporting period consistent with that of the utilities.)

Load Factor

Load factor is defined as the ratio of average demand to peak demand in any given period. More precisely, it is the energy demand in kilowatt hours divided by the product of the number of hours in the period, multiplied by the peak demand in kilowatt. (In a year-base, average demand equals annual energy consumption divided by 8760 hours per year.)

Table 5.7 shows that for the electric power industry in Canada as a whole, load factor has declined since 1960. This has occurred because peak demand has grown faster than energy demand (5.0 per cent compared with 4.7 per cent). In 1960, the industry load factor was 72.3 per cent, but by 1980 it had gradually reduced to 65.6 per cent. Since then, the load factor have varied around 65 per cent.

Tables and figures referred to in this chapter are on the following pages.

Tables & Figures

Table 5.1
Electricity Consumption by Province

	Electricity Consumption (GWh)					Average Annual Growth Rate (per cent)			
	1960	1970	1980	1990	1992*	1960-74	1975-92	1960-92	1991-92
Nfld.	1 427	4 770	8 545	10 422	10 696	11.5	3.3	6.5	0.9
P.E.I.	79	250	518	753	772	11.9	3.6	7.4	1.4
N.S.	1 733	3 706	6 814	9 678	9 908	8.7	3.3	5.6	1.3
N.B.	1 684	4 221	8 838	13 173	13 883	10.1	4.4	6.8	1.8
Que.	44 002	69 730	118 254	157 308	164 605	5.4	3.6	4.2	2.4
Ont.	37 157	69 488	106 509	142 818	139 383	6.4	2.7	4.2	-2.0
Man.	4 021	8 601	13 927	17 450	18 376	7.9	2.6	4.9	2.0
Sask.	2 124	5 402	9 827	13 589	14 590	9.2	4.3	6.2	5.6
Alta.	3 472	9 880	23 172	42 041	45 906	10.7	6.7	8.4	4.4
B.C.	13 413	25 761	42 789	57 206	57 270	6.9	3.4	4.6	-0.4
Yukon	89	220	381	485	480	9.3	1.8	5.4	3.2
N.W.T.	100	308	494	472	581	10.2	1.9	5.7	1.9
Canada	**109 304**	**202 337**	**340 068**	**465 395**	**476 450**	**6.6**	**3.5**	**4.7**	**0.9**

* Preliminary Data

Source: Electric Power Statistics, Volume II, Statistics Canada, catalogue 57-202

Table 5.2
Electricity Consumption in Canada by Sector

	Electricity Consumption (GWh)						Average Annual Growth Rate (per cent)	
	1960	1970	1980	1990	1991	1992	1960-92	1991-92
Residential	20 397	43 431	92 440	137 001	136 914	136 265	6.1	2.1
	(19)	(21)	(27)	(29)	(28)	(29)		
Commercial	12 632	44 068	75 912	110 057	108 587	111 489	7.0	1.5
	(12)	(22)	(21)	(24)	(23)	(23)		
Industrial	66 353	98 450	142 247	184 136	193 568	195 821	3.4	1.0
	(60)	(49)	(42)	(40)	(41)	(41)		
Line losses**	9 920	16 388	32 469	34 201	33 048	32 875	3.8	-4.0
	(9)	(8)	(10)	(7)	(7)	(7)		
Total	109 304	202 337	340 068	465 395	472 117	476 450	4.7	0.9
	(100)	(100)	(100)	(100)	(100)	(100)		

* Preliminary data.
** Losses during transmission, distribution and unallocated energy.
Figures in parentheses are percentage shares.

Source: Electric Power Statistics, Volume II, Statistics Canada, catalogue 57-202 and Natural Resources Canada

Table 5.3
Provincial Electricity Consumption and Generation, 1992

	Generation	Exports to Provinces	Exports to U.S.A.*	Imports from Provinces	Imports from U.S.A.	Consumption
	(GWh)					
Nfld.	36 681	25 985	0	0	0	10 696
P.E.I.	34	0	0	738	0	772
N.S.	9 722	67	0	253	0	9 908
N.B.	15 692	4 345	1 775	3 925	116	13 883
Que.	147 077	4 509	8 877	29 526	1 388	164 605
Ont.	138 518	201	5 303	2 203	4 166	139 383
Man.	26 763	3 113	6 250	965	11	18 376
Sask.	14 127	1 083	138	1 584	100	14 590
Alta.	47 520	2 016	0	399	3	45 906
B.C.	64 058	267	9 206	1 993	692	57 270
Yukon	480	0	0	0	0	480
N.W.T.	581	0	0	0	0	581
Canada	**501 523**	**41 586**	**31 549**	**41 586**	**6 476**	**476 450**

* Service exchange is included.

Source: Natural Resources Canada

Table 5.4
Per Capita Electricity Consumption by Province

	Per Capita Consumption (kWh/person)						Average Annual Growth Rate (per cent)	
	1960	1970	1980	1990	1991	1992	1960-92	1991-92
Nfld.	3 184	9 226	14 758	18 188	18 405	18 505	5.7	0.5
P.E.I.	765	2 273	4 177	5 748	5 809	5 893	6.6	1.4
N.S.	2 385	4 739	7 988	10 813	10 853	10 936	4.9	0.8
N.B.	2 864	6 732	14 850	18 245	18 736	19 044	6.1	1.6
Que.	8 565	11 597	18 735	23 556	23 485	23 770	3.2	1.2
Ont.	6 086	9 203	12 422	14 648	14 337	13 802	2.6	-3.7
Man.	4 932	8 750	13 521	16 024	16 548	16 751	3.9	1.2
Sask.	1 750	5 741	10 131	13 630	13 901	14 693	6.9	5.7
Alta.	2 695	6 194	11 135	17 000	17 429	17 911	6.1	2.8
B.C.	8 386	12 124	16 220	18 259	17 910	17 365	2.3	-3.0
Yukon	4 589	11 957	17 085	18 654	17 222	17 143	4.2	-0.5
N.W.T.	5 304	8 851	11 052	8 741	10 364	10 193	2.1	-1.6
Canada	**6 184**	**9 501**	**13 112**	**17 490**	**17 483**	**17 314**	**3.3**	**-1.0**

Source: Electricity Branch, Natural Resources Canada.

Table 5.5
Household Characteristics and Facilities in Canada, 1992

	Canada	Nfld.	P.E.I.	N.S.	N.B.	Que.	Ont.	Man.	Sask.	Alta.	B.C.
Total number of households(1000)	10 056	177	46	329	256	2 656	3 647	396	359	912	1 758
Average persons per household	2.6	3.2	2.8	2.7	2.8	2.5	2.7	2.6	2.6	2.7	2.5
Single dwellings* (%)	66	85	78	73	77	50	70	74	81	74	67
Electricity for space heating (%)	34	45	-	26	56	68	22	32	5	2	27
Air conditioners (%)	27	-	-	4	6	15	48	45	32	10	9
Electricity for cooking (%)	94	94	87	90	97	98	93	99	97	92	91
Microwave ovens (%)	76	69	70	77	76	73	78	76	81	81	74
Refrigerators (%)	99	99	96	99	100	99	100	99	100	99	100
Freezers (%)	58	76	63	64	69	48	57	68	81	69	58
Automatic dishwashers (%)	44	22	26	30	35	47	41	41	47	55	50
Electric washing machines (%)	79	92	83	81	88	84	74	75	86	80	74
Electric clothes dryers (%)	74	75	72	73	82	78	70	73	84	78	71
Colour TV sets (%)	98	97	96	98	98	98	98	97	97	97	97

* Including mobile homes.

Source: Household Facilities and Equipment, 1992, Statistics Canada, catalogue 64-202

Table 5.6
Peak Demand by Province

	Peak Demand (MW)						Average annual Growth Rate (per cent)	
	1960	1970	1980	1990	1991	1992*	1960-92	1991-92
Nfld.	245	763	1 538	1 848	1 837	1 826	6.5	-0.6
P.E.I.	21	55	104	135	137	138	6.1	0.7
N.S.	356	814	1 197	1 825	1 806	1 821	5.2	0.8
N.B..	319	726	1 699	2 627	2 777	2 708	6.9	-2.5
Que.	5 871	11 127	20 680	29 259	31 104	30 449	5.3	-2.1
Ont.	6 391	12 048	17 767	23 752	24 096	23 027	4.1	-4.4
Man.	772	1 565	2 681	3 524	3 398	3 401	4.7	0.1
Sask.	418	1 028	2 085	2 356	2 234	2 455	5.7	9.9
Alta.	714	1 894	3 879	6 509	6 452	6 758	7.3	4.7
B.C.	2 123	4 492	7 384	9 329	8 901	10 064	5.0	13.1
Yukon	19	39	75	81	84	87	4.9	3.6
N.W.T.	15	41	81	107	102	102	6.2	0.0
Canada	17 264	34 592	59 170	81 352	82 963	82 836	5.0	-0.2

* Preliminary Data

Source: Electric Power Statistics, Volume I, Statistics Canada, catalogue 57-204

Table 5.7
Load Factor by Province

	1960	1965	1970	1975	1980	1985	1990	1991	1992
				(per cent)					
Nfld.	66.5	72.6	71.4	68.7	65.3	64.5	64.4	65.9	66.9
P.E.I.	66.4	65.4	65.8	65.4	68.4	64.9	63.7	63.3	63.9
N.S.	59.5	66.4	62.7	58.4	59.3	62.0	60.5	61.8	62.1
N.B.	58.0	60.3	60.0	62.2	53.8	62.5	57.2	56.1	58.5
Que.	85.6	72.5	71.5	67.9	65.3	64.5	61.4	59.0	61.7
Ont.	66.4	65.4	65.8	65.4	68.4	64.9	68.6	67.4	69.1
Man.	59.5	66.4	62.7	58.4	59.3	62.0	56.5	60.5	61.7
Sask.	58.0	60.3	60.0	62.2	53.8	62.5	65.8	70.6	67.8
Alta.	55.5	57.1	59.6	64.2	68.2	72.3	73.7	77.8	77.5
B.C.	72.1	71.6	65.5	64.4	66.2	66.1	70.0	73.8	65.0
Yukon	53.5	77.8	64.4	60.9	58.0	54.3	68.4	63.2	63.0
N.W.T.	76.1	58.6	85.8	71.3	69.6	70.6	50.4	63.8	65.0
Canada	72.3	68.1	66.8	65.7	65.6	65.1	65.3	65.0	65.7

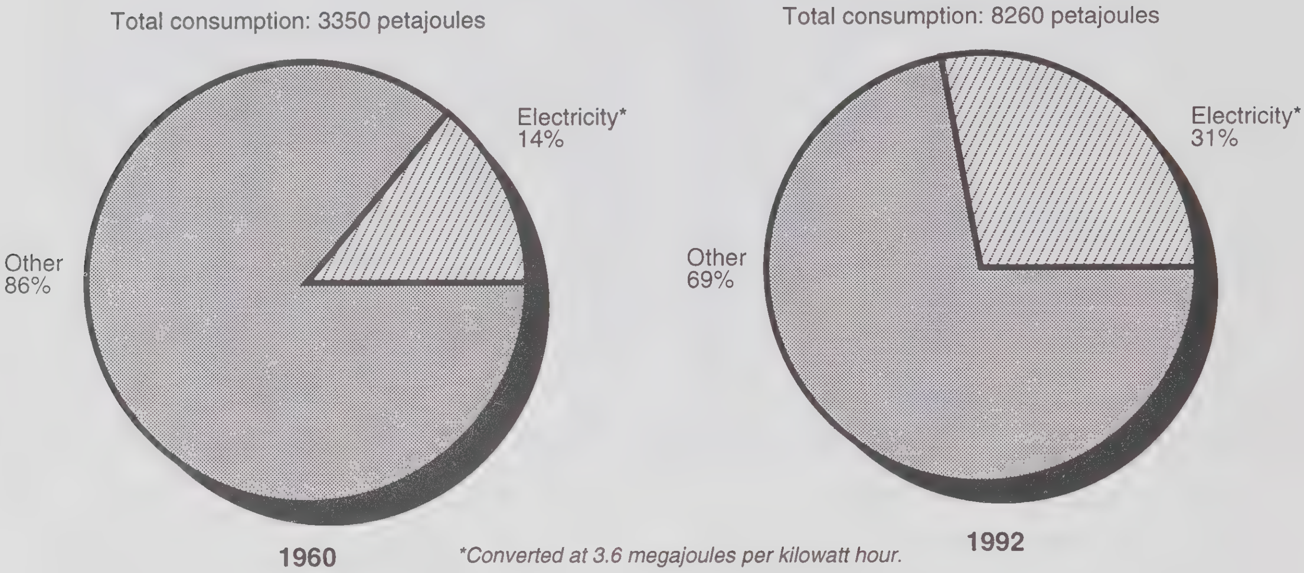
Source: Calculated from Tables 5.1 and 5.6

Table 5.8
Days of Peak Demand, Winter 1992-93

Province	Day
Newfoundland - Labrador	January 13
Newfoundland - Island	January 20
Prince Edward Island	December 17
Nova Scotia	January 19
New Brunswick	January 30
Quebec	February 7
Ontario	February 1
Manitoba	January 8
Saskatchewan	December 17
Alberta	December 17
British Columbia	January 11
Yukon	January 28
Northwest Territories	January 26

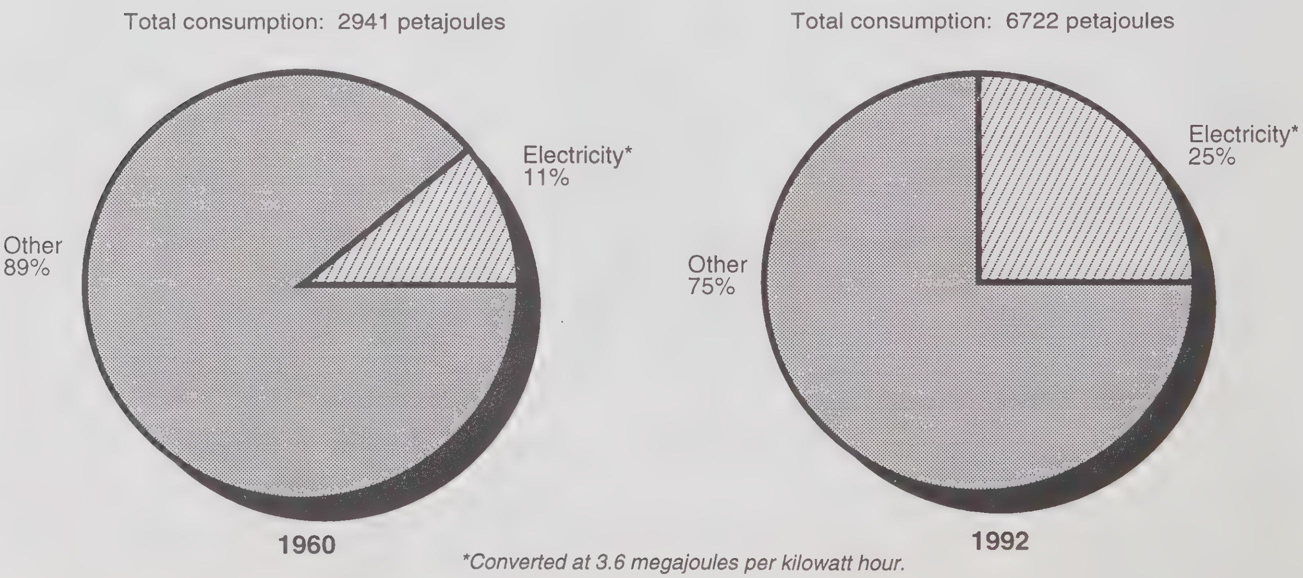
Source: Statistics Canada

Figure 5.1 Primary Energy Consumption in Canada



*Converted at 3.6 megajoules per kilowatt hour.

Figure 5.2 Secondary Energy Consumption in Canada



*Converted at 3.6 megajoules per kilowatt hour.

Figure 5.3
Electricity Generation, Consumption and Net Transfers, 1992 (GWh)

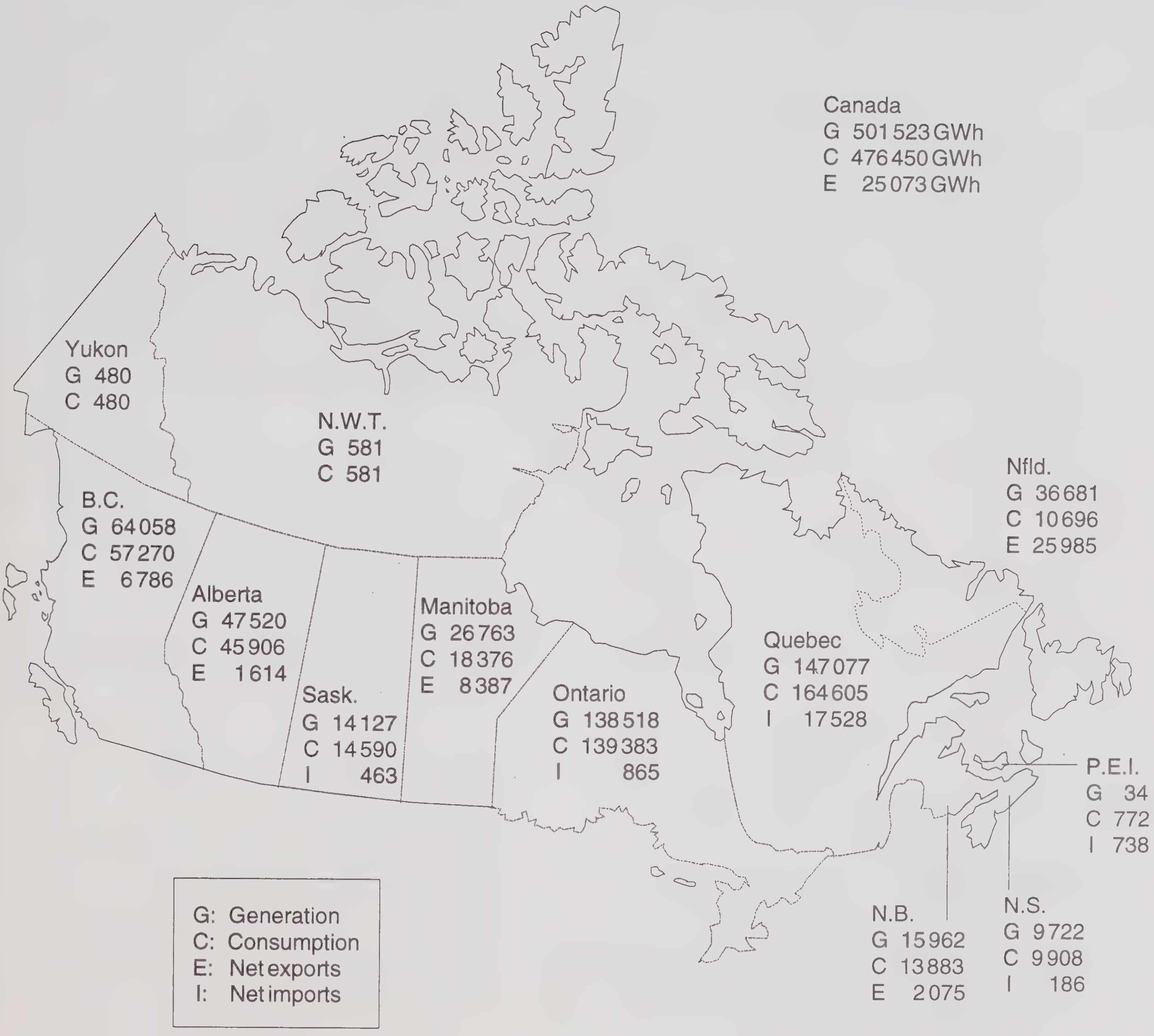
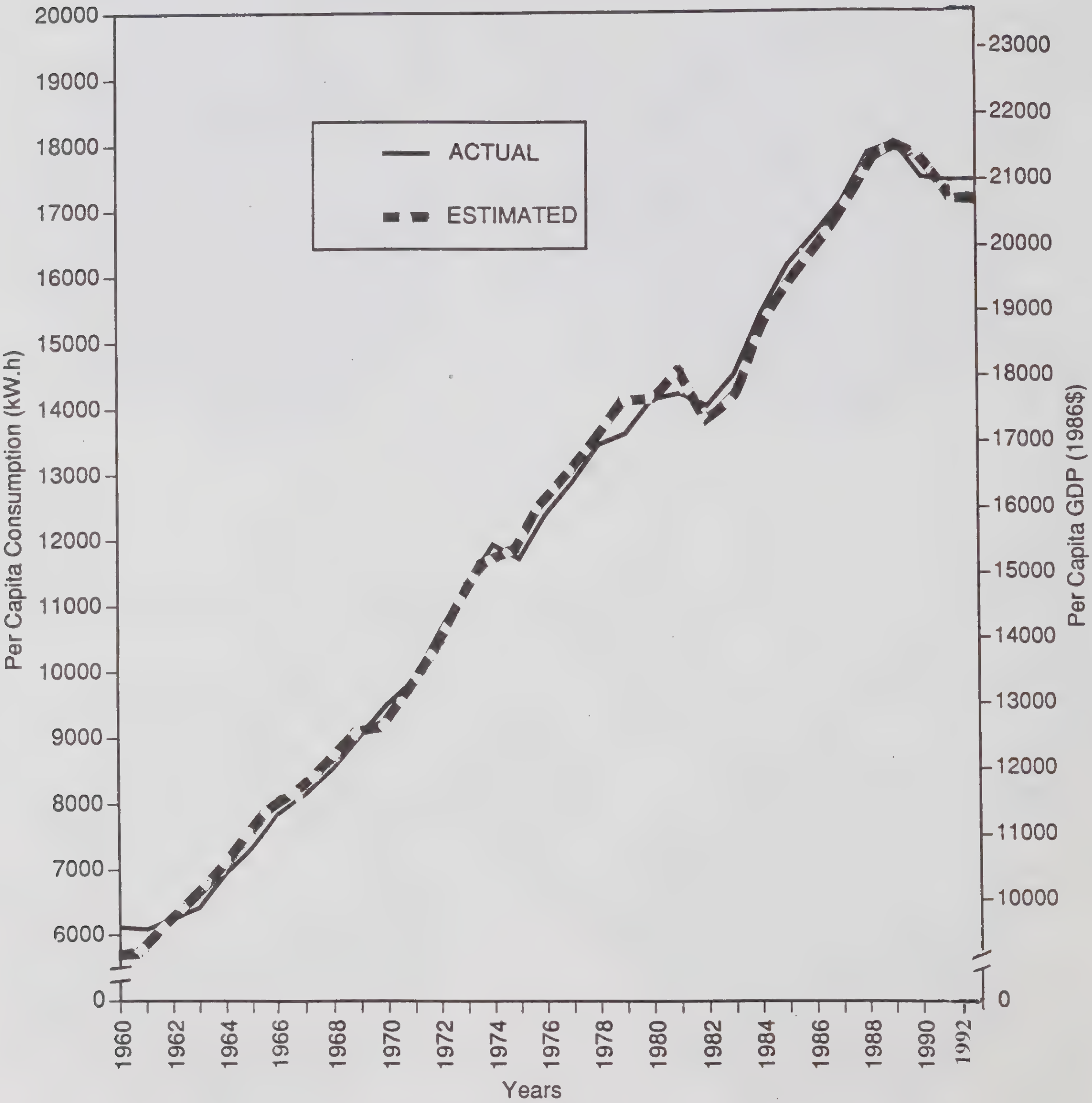


Figure 5.4 Historical Relationship Between Electricity Demand and GDP, 1960-1992



Chapter 6

Electricity Generation

Sources of Generation

Canada's electric power industry began in the 1880s with electricity generated by steam. In the beginning, electricity was used mainly for home and street lighting. In the late-1880s and 1890s, the invention of the electric motor dramatically changed the industry from one that mainly provided nighttime power for lighting to one that also provided power for transportation and industrial needs, 24 hours a day. Following this development, the use of hydroelectricity spread rapidly due to Canada's abundant water resources. In 1920, hydro accounted for more than 97 per cent of total electricity production in Canada. This percentage declined slightly to 95 per cent by 1950, and 92 per cent by the end of 1960. By 1992, hydro production had further declined to about 62 per cent (Table 6.1 and Figure 6.2).

Thermal generation, mainly from coal-fired stations, has been a part of Canada's generation mix since the beginning of the electric power industry. However, for many years its share of total production did not increase significantly because of its relatively high cost of production. This situation changed by the 1960s and 1970s, when most of Canada's economical hydro sites had been developed, and thermal generation became competitive.

Between 1950 and 1974, the growth rate of real fossil-fuel prices (coal, oil and natural gas) was negative -- a situation that led most electric utilities to build more thermal stations. As Table 6.1 indicates, thermal generation accounted for only 7 per cent of the total generated electricity in 1960. However, its production share jumped to 23 per cent by 1970, and reached a peak of 25 per cent in 1974. After the first oil crisis of 1973-74, fossil-fuel prices increased substantially, averaging more than 15 per cent during the 1975-85 period. As a result, the share of thermal production gradually declined to 22 per cent by 1980, and 20 per cent by 1985. With the collapse of oil prices in 1986, thermal generation once again became economical. As a result, thermal production's share rose to 22 per cent in 1990 and 1991, and up to 23 per cent in 1992.

The production of nuclear power began in Canada in 1962 when the 25-MW Rolphton station went into operation. In 1968, commercial operation started at the 220-MW Douglas Point station in Ontario, owned by Atomic Energy of Canada Ltd. During the 1970s, nuclear production emerged as an important source of electricity in Canada, and by 1975 nuclear generation accounted for more than 4 per cent of total electricity production. Most of the nuclear generation came from the first four Pickering stations in Ontario, which were completed between 1971-73. By 1980, the nuclear production share increased to about 10 per cent of Canada's total, with the completion of four of Ontario's Bruce stations.

By 1985, nuclear generation accounted for 13 per cent of Canada's total generated electricity. Between 1980 and 1985, seven nuclear stations were brought into service: Gentilly 2 in Quebec; Point Lepreau in New Brunswick; Pickering stations 5, 6 and 7, and Bruce stations 5 and 6, all located in Ontario. By 1992, the nuclear generation share had increased to about 15 per cent with the commissioning of Pickering 8, Bruce 7 and 8, and Darlington 2 and 1, all of which went into operation in 1986, 1987, 1990 and 1992.

To date, tidal power has played an insignificant role in electricity generation in Canada. However, it is worth noting that the 20-MW Annapolis tidal power plant in Nova Scotia, which began operation in 1984, is the first of its kind in North America. As compared to conventional hydro plants, this plant requires higher maintenance levels because of salt water

exposure. However, considering greater maintenance levels, the plant has operated without any major difficulties since 1984.

Hydroelectric Power Development

Canada's rapid development of hydroelectric power in the past was mainly attributed to two factors: abundant water resources and the nationalization of private provincial electric utilities. The former provided the least-cost energy production, and the latter enabled the provincial government to use the public enterprise as an instrument to serve government industrial policy and other objectives.

In the first half of the century, the influence of government objectives on the structure of the industry was mainly focusing on the level and structure of prices and the need for universal service - the types of concerns traditionally addressed through government control over monopolies. It was in this period that Ontario Hydro (1906), Hydro-Québec (1944), Manitoba Hydro (1949), and British Columbia Power Commission (1946) were created.

Since 1950, electric utilities have come to be seen in a broader context, especially for those provinces endowed with hydroelectric power resources. Given the amount and importance of their capital expenditures to provincial economies, it was recognized that hydroelectric power development could serve such policy objectives as job creation, industrial development, and macro-economic stabilization. During this more recent period, nationalizations occurred that led to a major expansion of the publicly owned electric utilities in British Columbia and Quebec.

During the 1960s, the provincial government assumed a major role in promoting the modernization of Quebec society and increased francophone control over the provincial economy. Government enterprise was one of the main instruments used to achieve those objectives.

The nationalization of the private electric utilities in the province was among the more dramatic initiatives taken during this period. While Hydro-Québec had been established since 1944, in the early 1960s over half the electric power in the province was still being provided by investor-owned firms. The nationalization that occurred in 1963 was in part justified by the need to integrate the system and coordinate investment. All major hydro projects (James Bay Phase I and Manic) in Quebec were developed after 1963 in coordination with industrial development and increased employment.

The same is true for British Columbia and Manitoba. British Columbia Hydro & Power Authority (B.C. Hydro) was incorporated in 1962 by merging B.C. Power Commission and B.C. Electric Limited which was nationalized in 1961. B.C. Hydro is a Crown corporation providing electrical service throughout the province, with the exception of the south interior, which is served by the West Kootenay Power and Light Company Limited. The most important hydro projects in British Columbia, Gordon M. Shrum, Revelstoke, and Mica, were all built after 1962 to serve the provincial government's policy purposes.

Manitoba Hydro's mandate under the 1970 *Manitoba Hydro Act* is to provide adequate power supply to meet the needs of the province and to promote economy and efficiency in the generation, distribution, supply, and use of power. With these government policy objectives, two major hydro projects, Kettle Rapide and Long Spruce, were commissioned in 1970 and 1977, respectively.

Electricity Generation in 1992

Electricity generation increased by 2.3 per cent in 1992, which is much greater than 0.9 per cent of the domestic electricity demand. The increase is mainly attributed to a greater number of exports to the United States and stronger domestic demand in Quebec, Saskatchewan, and Alberta. Of the total electricity generated in 1992, 469 974 GWh was for use in Canada and the remaining 31 549 GWh was exported. The sources of generation are given in Table 6.1, and the major generating stations in each province are shown in Figure 6.1.

Between 1960 and 1992, hydro production dropped from 92 per cent to 62 per cent, as shown in Figure 6.2. Natural gas production also decreased (from 4 per cent in 1960 to 2 per cent in 1992), while oil increased (from 1 per cent to 3 per cent over the same period). With the first oil crisis of 1973-74, electric utilities were discouraged from using natural gas and oil for baseload electricity generation. However, as noted above, the collapse of oil prices in 1986 has made electricity generation from oil more economical.

Nuclear's share of production had the largest gain, moving from zero in 1960 to about 15 per cent by 1992; coal production increased from 3 per cent to 17 per cent over the same period. These increases have occurred at the expense of hydro. With the relatively cheap fuel prices of uranium and coal and the development of most of the country's economical hydro sites, hydro's share of production has declined significantly since 1960.

Electrical energy production by fuel type by province in 1992 is reported in Table 6.2. In Newfoundland, Quebec, Manitoba, and British Columbia, hydro generation accounted for more than 95 per cent of the total. In Alberta, about 81 per cent of total generation came from coal. Coal generation was also important in Saskatchewan and Nova Scotia, at 70 per cent and 62 per cent respectively. In Ontario, coal, nuclear and hydro production are well balanced, while in New Brunswick, total generation is a mix of oil, nuclear, hydro and coal.

Ontario, Quebec and New Brunswick are the only three provinces that produce nuclear energy in Canada. In 1992, nuclear generation accounted for 48 per cent of Ontario's total electricity generation, 31 per cent of New Brunswick's, and 3 per cent of Quebec's. Electricity generation from natural gas occurs mainly in industries that generate power for their own use. In all provinces except Newfoundland, Nova Scotia and New Brunswick, oil is used mainly for peaking purposes.

Generation by Province

Table 6.3 shows electricity generation by province during the period 1960-92, and generation growth rates for 1992 over 1991 and the period 1960-92. Newfoundland had the greatest production growth during the period 1960-92, with an average growth rate of 10.5 per cent. This was due mainly to the completion of the Churchill Falls hydro station (5429 MW) in Labrador in 1974. Over 90 per cent of the electricity produced at Churchill Falls flows into Quebec under a contract that ends in the year 2041.

Electricity generation fluctuated significantly in Prince Edward Island during the period 1960-92. The province's electrical generating plants are relatively small, fuelled by oil, and are consequently expensive to operate. In 1977, an interprovincial interconnection was completed, allowing P.E.I. to purchase electrical energy from New Brunswick. In addition, in 1981, P.E.I. purchased a 10 per cent ownership interest in the 200-MW coal/oil-fired plant at Dalhousie, New Brunswick. The interconnection and joint

ownership has enabled P.E.I. to reduce the amount of generation from its own oil-fired stations.

In 1992, there was negative growth in electricity generation in Newfoundland, Prince Edward Island, and Ontario (Table 6.3). However, Manitoba had a substantial increase, which was attributed to completion of the remaining three units at the Limestone hydroelectric project.

Figure 6.3 presents electricity generation by region. Although Quebec has been the largest electricity producer in Canada since 1960, its share has declined from 44 per cent in 1960 to 29 per cent in 1992. Ontario was the second-largest producer, with 28 per cent in 1992, compared with 31 per cent in 1960. British Columbia has remained the third largest electricity producer over the period, generally providing 13 per cent of the total. Electricity generation growth rates for Newfoundland, Nova Scotia, New Brunswick, Manitoba, Saskatchewan and Alberta were all greater than those for Quebec, Ontario and British Columbia during 1960-92. This indicates that generation shares for the Atlantic and Prairie provinces are increasing at the expense of the top three provinces.

Fossil-Fuel Requirements

Because of the rapid expansion of coal-fired stations in the 1960s and 1970s, coal consumption increased about tenfold during the period 1960-75, and more than doubled in the following ten years. However, in recent years, environmental concerns have led to a more gradual increase in its use.

The use of natural gas and oil for electricity generation peaked in the mid-1970s and 1980, and then declined sharply. However, with the collapse of international oil prices in 1986, the situation reversed itself and it again became economical for electric utilities to use oil and natural gas for electricity generation (Tables 6.4 and 6.5). The use of uranium has increased dramatically since 1970 with the growth of nuclear capacity in Canada, particularly in Ontario.

In 1992, provinces west of Quebec continued to use Canadian oil, primarily light oil and diesel oil, in gas turbines or diesel plants. In the Yukon and Northwest territories, Canadian diesel oil was used to supply electricity to small remote communities. Oil used by the Atlantic region and Quebec was imported.

In 1992, about 62 per cent of the coal used for electricity generation in Ontario was imported from the United States, while the remainder came from western Canada. Coal used by Manitoba was purchased from Saskatchewan, while Alberta, Nova Scotia and New Brunswick used their own coal resources. Saskatchewan relied primarily on its own coal, but also purchased additional amounts from Alberta.

Heat Content of Fuel

According to Statistics Canada, heat content for the same type of fuel used for electricity generation varies from province to province. For instance, Canadian bituminous coal used in Nova Scotia has 27 337 kilojouls per kilogram, compared with 17 311 kilojouls per kilogram in Alberta. The same is true for light, heavy, and diesel fuel oil used for electricity generation. Table 6.6 summarizes heat content for various fuels used in electricity generation in Canada in 1991.

Emissions from Electricity Generation

As shown in Table 6.1, 113 367 GWh of electricity came from conventional thermal sources, which accounted for about 23 per cent of total electricity generated in 1992. This amount of thermal generation required a considerable quantity of fossil fuels: 45 million tonnes of coal; 3.5 million cubic metres of oil; and 3111 million cubic metres of natural gas (Table 6.5). In 1992, about 90 per cent of the total coal consumption in Canada was used for electricity generation. The percentage shares for natural gas and oil are 4.2 per cent and 3.7 per cent, respectively.

The combustion of fossil fuels can produce carbon dioxide, sulphur dioxide, nitrous oxides, etc. Emissions from electricity generation in 1992 are presented in Table 6.7. In 1992, more than 56 per cent of the total sulphur dioxide emission in Canada came from the electric power industry, compared with 20 per cent of carbon dioxide and only 14 per cent of nitrous oxides emissions.

Tables and figures referred to in this chapter are on the following pages.

Tables & Figures

Table 6.1
Sources of Electricity Generation

Fuel Type	Electricity Generation 1960	1970	1980	1990	1991	1992	Average Annual Growth Rate 1960-92	1991-92
	(GWh)						(per cent)	
Hydro	105 883	156 709	251 217	292 810	304 308	312 100	3.4	2.6
Thermal	8 495	47 045	80 207	104 121	105 986	113 367	8.4	7.0
Nuclear*	-	969	35 882	68 837	80 122	76 022	-	-5.1
Tidal**	-	-	-	26	32	34	-	6.3
Total	**114 378**	**204 723**	**367 306**	**465 744**	**490 448**	**501 523**	**4.8**	**2.3**

* Commercial operation started in 1968.
** Commercial operation started in 1984.

Source: Electric Power Statistics, Volume (II), Statistics Canada, catalogue 57-202, and Electric Power Statistics Monthly, Statistics Canada, catalogue 57-001

Table 6.2
Electrical Energy Production by Fuel Type, 1992

	Coal	Oil	Natural Gas	Nuclear	Hydro	Other	Total
			(GWh)				
Nfld.	0	1 801	0	0	34 880	0	36 681
P.E.I.*	0	34	0	0	0	0	34
N.S.	5 994	2 676	0	0	896	156	9 722
N.B.	1 195	6 687	0	4 835	2 972	273	15 962
Quebec	0	1 125	0	4 600	141 352	0	147 077
Ontario	27 470	649	2 338	66 587	39 719	1 755	138 518
Manitoba	269	3	7	0	26 434	50	26 763
Sask.	9 957	46	891	0	3 055	178	14 127
Alberta	38 677	0	5 888	0	1 585	1 370	47 520
B.C.	0	338	1 669	0	60 555	1 496	64 058
Yukon	0	61	0	0	419	0	480
N.W.T.	0	219	95	0	267	0	581
Canada	**83 562**	**13 639**	**10 888**	**76 022**	**312 134**	**5 278**	**501 523**

* PEI has 10 per cent ownership in New Brunswick's Dalhousie coal-fired station, unit 2.

Source: Natural Resources Canada

Table 6.3
Electricity Generation by Province

	Electricity Generation						Average Annual Growth Rate	
	1960	1970	1980	1990	1991	1992	1960-1992	1991-1992
	(GWh)						(%)	
Nfld.	1 512	4 854	46 374	36 585	36 967	36 681	10.5	-0.8
P.E.I.	79	250	127	81	71	34	-2.6	-52.1
N.S.	1 814	3 511	6 868	9 430	9 385	9 722	5.4	3.6
N.B.	1 738	5 142	9 323	16 665	15 762	15 962	7.2	1.3
Quebec	50 433	75 877	97 917	135 458	142 281	147 077	3.3	3.4
Ontario	35 815	63 857	110 283	129 343	141 179	138 518	4.3	-1.9
Manitoba	3 742	8 449	19 468	20 149	22 871	26 763	5.8	17.0
Sask.	2 204	6 011	9 204	13 540	13 576	14 127	6.0	4.1
Alberta	3 443	10 035	23 451	42 874	44 340	47 520	8.5	7.2
B.C.	13 409	26 209	43 416	60 662	62 981	64 058	5.0	1.7
Yukon	89	224	381	485	465	480	5.4	3.2
N.W.T.	100	304	494	472	570	581	5.7	1.9
Canada	114 378	204 723	367 306	464 744	490 448	501 523	4.7	2.3

Source: Electric Power Statististics, Volume (II), Statistics Canada, catalogue 57-202

Table 6.4
Fuels Used to Generate Electricity in Canada

	1960	1965	1970	1975	1980	1985	1990	1991	1992
Coal (10^3) tonnes	1 674	7 004	13 786	16 567	27 785	39 456	41 822	45 241	45 374
Oil (10^3) cubic metres	328	871	1 869	2 309	2 867	1 391	3 888	2 983	3518
Natural Gas (10^3) cubic metres	1 069	1 679	1 992	4 009	1 875	1223	3 084	1 092	3111
Uranium (tonnes)	0	2	16	194	685	1 086	1 386	1 406	1507

Source: Electric Power Statistics, Volume (II), Statistics Canada, catalogue 57-202, and Natural Resources Canada

Table 6.5
Fuels used to Generate Electricity by Province, 1992*

	Coal (10^3 tonnes)	Oil (10^3 cubic metres)	Gas (10^6cubic metres)	Uranium (tonnes)
Nfld.	0	454	0	0
P.E.I.	33	16	0	0
N.S.	2 342	650	0	0
N.B.	481	1 678	0	92
Quebec	0	308	0	86
Ontario	10 219	214	672	1 329
Manitoba	122	0	3	0
Sask.	8 403	3	291	0
Alberta	23 744	0	1 638	0
B.C.	0	107	484	0
Yukon	0	17	0	0
N.W.T.	0	71	13	0
Canada	**45 374**	**3 518**	**3 111**	**1 507**

Note: 1 cubic metre oil = 6.3 barrels; 1 barrel of oil is defined as 5 800 000/BTU.
1 cubic metre gas = 35.5 cubic feet; 1 cubic foot of natural gas is defined as 1000 BTU.
1 tonne = 1000 kilograms; 1 gram of uranium is defined as 603 825 BTU.
* Preliminary Data

Source: Natural Resources Canada

Table 6.6
Heat Content in Canada, 1991

	Canadian Bituminous (kg)	Imported Bituminous (kg)	Sub-Bituminous (kg)	Lignite (kg)	Light Fuel Oil (litre)	Heavy Fuel Oil (litre)	Diesel (litre)	Natural Gas (m^3)	Uranium (g)
					(kilojouls)				
Nfld.	-	-	-	-	38 413	42 694	38 170		
P.E.I.	-	-	-	-	-	41 397	35 611		
N.S.	27 337	-	-	-	37 580	41 929	37 582		
N.B.	26 901	-	-	-	38 740	41 409	39 113		576 200
Que.	-	-	-	-	38 680	42 122	46 500		621 000
Ont.	37 509	28 579	-	15 942	38 479	42 421	37 699	37 446	704 488
Man.	-	-	-	-	37 814	37 814	33 040	37 222	
Sask.		-	-	14 636	37 100	37 100	38 000	37 348	
Alta.	17 311	-	18 352	-			37 912	38 047	
B.C.	-	-	-	-			36 160	38 427	
Yukon	-	-	-	-			41 321		
N.W.T.	-	-	-	-			37 000		
Canada	**30 934**	**28 579**	**18 352**	**14 837**	**38 402**	**41 824**	**39 256**	**38 042**	**690 687**

Source: Electric Power Statistics Volume II, Statistics Canada, Catalogue 57-202

Table 6.7
Emissions from Electricity Generation, 1992

	SO_2 (1000 tonnes)	NO_x (1000 tonnes)	CO_2 (1000 tonnes)
Newfoundland	19	3	1 360
Prince Edward Island	1	0	47
Nova Scotia	143	26	7 417
New Brunswick	148	28	6 400
Quebec	10	0	0
Ontario	157	53	27 120
Manitoba	0	0	315
Saskatchewan	73	28	11 887
Alberta	106	58	42 892
British Columbia	0	2	874
Yukon	2	0	51
Northwest Territories	2	0	208
Electric Utilities' Total	661	198	98 571
Canada's Total Resulting from Energy Activities	1 171	1 644	505 631
Electric Utilities' Share (%)	56	12	20

Source: Electric Utilities and Natural Resources Canada

Figure 6.1 Major Generating Stations by Province, 1992 (MW)

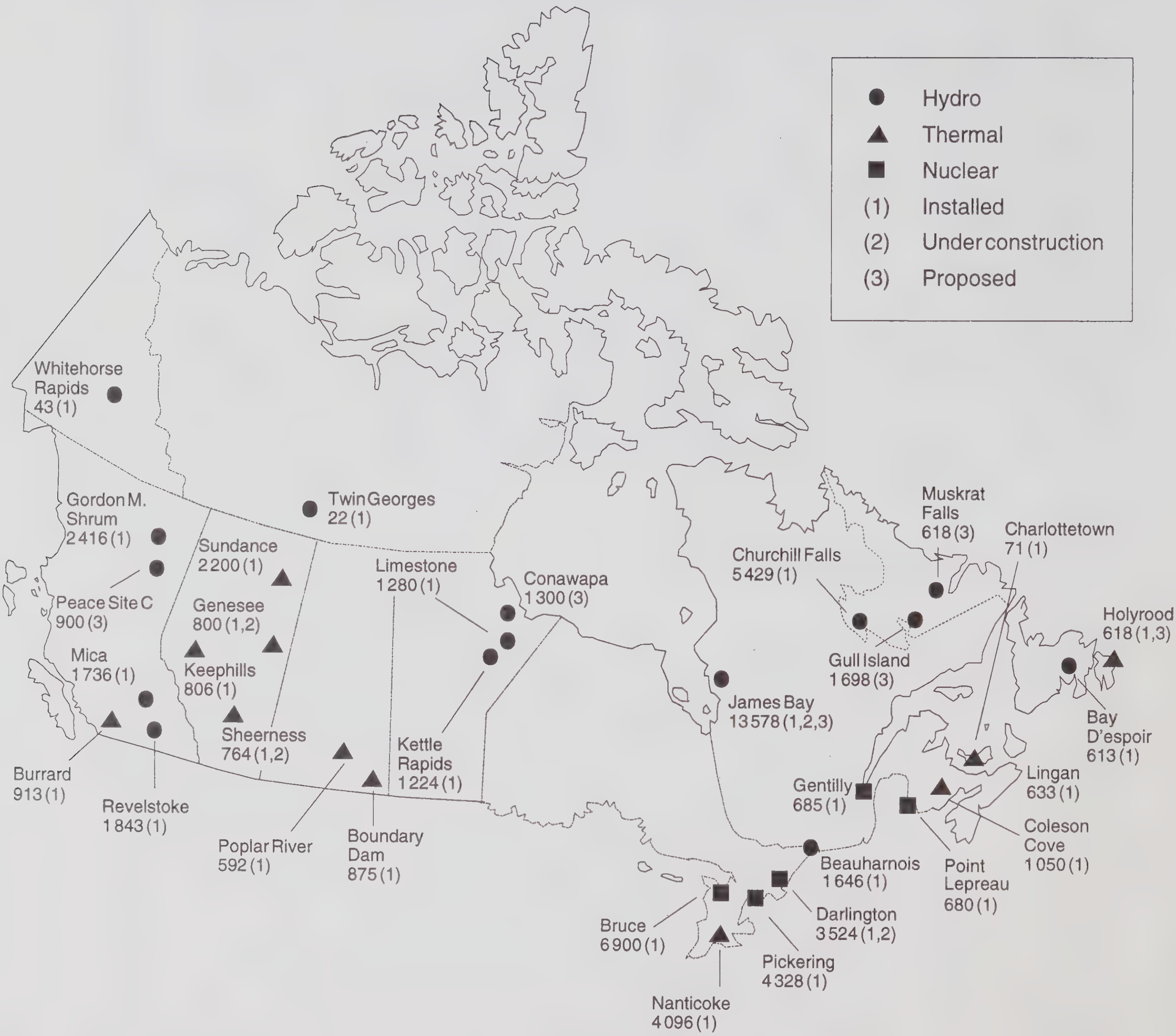
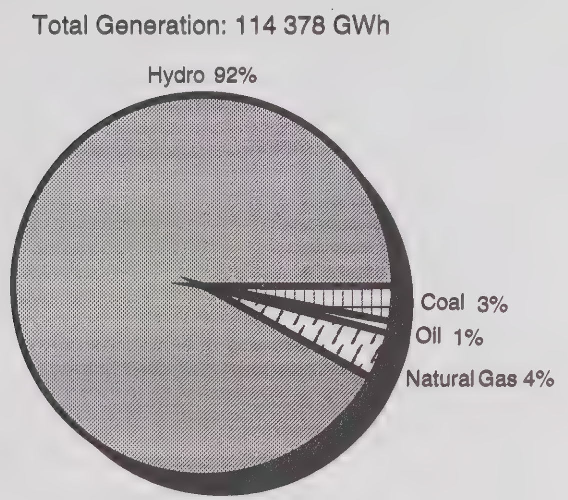
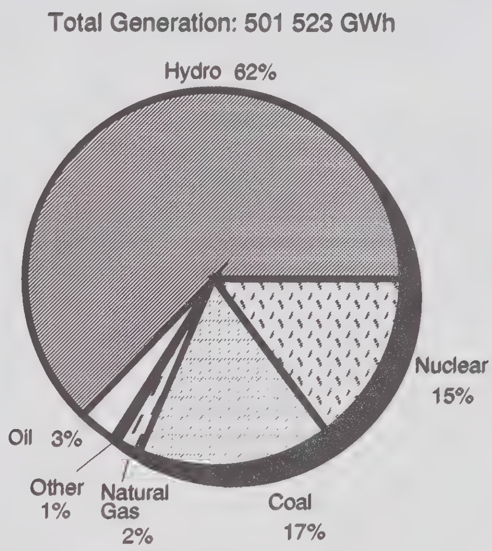


Figure 6.2 Electricity Generation by Fuel Type

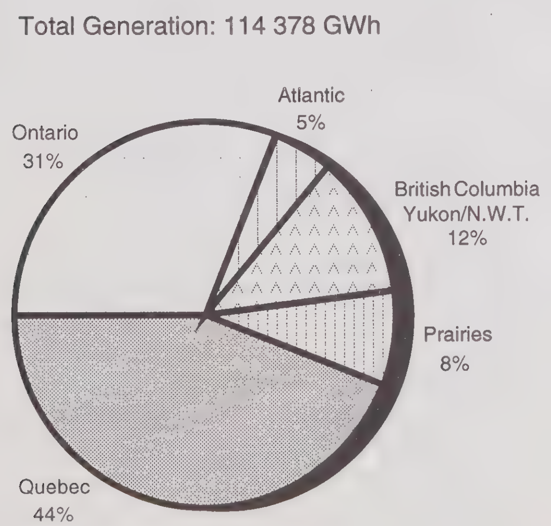


1960

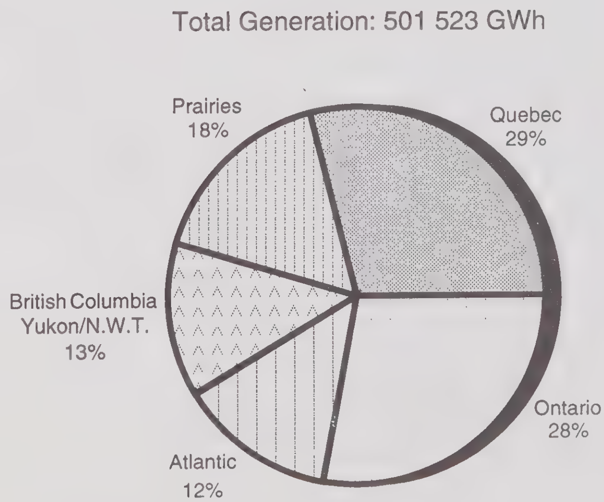


1992

Figure 6.3 Electricity Generation by Region



1960



1992

Chapter 7

Generating Capacity and Reserve

To meet load requirements, an electric power system must have sufficient installed generating capacity to satisfy the peak demand and the capability to supply the total energy requirements.

As discussed in Chapter 6, Canada's first electrical generating stations were thermal. As the demand for electricity grew and technology developed, hydroelectric power grew in importance, primarily for economic reasons. The use of hydroelectricity spread rapidly due to Canada's abundant water resources.

In 1920, hydro accounted for 86 per cent of total generating capacity, and by 1945, hydro's share of total installed capacity peaked at 94 per cent. Since then, the capacity share of hydro has declined gradually, reaching about 81 per cent by 1960, 58 per cent in 1980, and 57 per cent in 1992 (Table 7.1).

Several factors have contributed to the gradual reduction in the capacity share of hydro since the end of World War II. By 1945, many of Canada's economic hydro sites had been developed. Moreover, the growth rates of real fossil-fuel prices (coal, oil and natural gas) were negative between 1950 and 1974, a situation that led many utilities to construct thermal stations during this period. In addition, in the early 1960s, Canada began to develop nuclear energy as an alternative means of electricity generation.

Capacity Additions

There were only a few major capacity additions in 1992. This may be a result of energy conservation efforts and economic recession.

In October 1992, a 56 MW hydro generating unit went into service at Hydro-Québec's Manic 5 PA power station. Three units (3 x 317 MW) at the La Grande 2A hydro station were commissioned in 1992. In addition, the first unit of 2x195 MW gas turbine at Becancour station was also completed in October 1992.

The last three units of Manitoba's Limestone hydroelectric project (10x133 MW) went into service between February and August 1992.

The 300 MW unit at the Shand coal-fired station, owned by SaskPower was declared in-service in July 1992. This facility is one of the most environmentally advanced coal-fired power stations in Canada. Its features include the Finnish LIFAC lime-injection system to significantly reduce sulphur dioxide emissions; air and temperature controlled burners to reduce nitrogen oxide formation and improve efficiency; an electrostatic precipitator for particulate control (and a zero-discharge system to prevent other contaminants from escaping to the environment.)

Unit number 1 of Ontario Hydro's Darlington nuclear station (4x881 MW) went into service in November 1992; unit number 2 was completed earlier in October 1990; and the remaining two units are to be commissioned in 1993. The gross installed capacity for each unit is 935 MW.

There were 5 MW and 9 MW diesel stations completed in the Yukon and Northwest Territories respectively, in 1992.

Capacity by Fuel Type and Province

Total installed capacity by fuel type and province for 1992 is given in Table 7.2. Although hydro's share of total installed capacity has declined, hydro is still the predominant source of electrical energy in Canada. In 1992, hydro's capacity share accounted for 57 per cent of total installed capacity, followed by coal 18 per cent, nuclear 13 per cent, oil 7 per cent, natural gas 3 per

cent, and other (wood, flare gas, etc.) 2 per cent (Figure 7.1).

In the 1960s and early-1970s, Quebec had the largest installed capacity in Canada. Since the mid-1970s, however, Ontario's capacity has been the largest. In 1992, Ontario's installed capacity was 31 per cent of the Canadian total, followed by Quebec with 29 per cent and British Columbia with 12 per cent. The combined total of these three provincial electrical systems accounted for 72 per cent of the total. Between 1960 and 1992, the Atlantic provinces had a major gain; their share increased from 5 per cent in 1960 to 13 per cent by 1992. This increase was due to the completion of the Churchill Falls project in Labrador in 1974, (Figure 7.2). Other regions of Canada have shown substantial installed generating capacity by province for the period 1960-92 (Table 7.3.).

Major Hydro Stations in Canada

Canada is a world leader in large hydro-station design, construction and operation. Table 7.4 lists Canada's ten largest hydro stations in 1992. Churchill Falls, Canada's largest hydro plant (5429 MW), ranked sixth among the world's hydro plants by present capacity. La Grande 2, situated in the James Bay region of Quebec, is Canada's second-largest hydro plant with 5328 MW and ranked seventh in the world. La Grande 4, also in Quebec, ranked seventeenth. British Columbia's Gordon M. Shrum hydro plant and Quebec's La Grande 3 ranked twenty-first and twenty-third among the world's largest hydro plants in 1992[1].

Among Canada's ten largest hydro plants, five are located in Quebec, mainly in the James Bay area, three in British Columbia, and one each in Newfoundland and Ontario. These ten hydro stations have a total installed capacity of 25 935 MW, and in 1992 they accounted for about 42 per cent of Canada's total hydro capacity. Many smaller, but strategically important, hydro facilities are located throughout the country.

Major Conventional Thermal (Fossil) Stations in Canada

Canada has significant long-term experience with a variety of thermal technologies of all sizes. In the 1950s and early-1960s, Canadian electric utilities built many steam plants with unit sizes from tens of MW to as large as 300 MW. Since then, advances in technology, stable fossil-fuel prices, and robust electricity demand growth have supported the development of larger steam plants. For example, Ontario Hydro's Lambton and Nanticoke coal-fired stations have unit sizes of 510 MW and 512 MW respectively, while the Lennox oil-fired station has four units of 550 MW. Electric utilities in Alberta have constructed a number of coal-fired stations with unit sizes in the 400 MW range.

Table 7.5 lists Canada's ten largest thermal stations in 1992. Seven of the ten stations are using coal as input fuel, two oil and one natural gas. Five of the ten largest thermal stations are located in Ontario, where a large population results in significant economies of scale. Two of the stations are in Alberta, and there is one each in New Brunswick, Saskatchewan and British Columbia. Total combined capacity for these stations is 17 780 MW, which accounted for 55 per cent of Canada's total conventional thermal installed capacity in 1992.

[1] *International Water Power and Dam Construction, June 1993.*

Nuclear Power Stations in Canada

In the early-1960s, Canada started to develop nuclear energy as an alternative source for future energy demand. By 1992, Canada owned and operated 20 large CANDU reactors (500 MW and up), with a total installed net capacity of 13 629 MW. With the exceptions of Point Lepreau 1 in New Brunswick and Gentilly 2 in Quebec, they are all located in Ontario. Table 7.6 reports major nuclear power stations in Canada, in order of their commissioning date.

CANDU reactors (pressurized heavy water reactors) have been shown to be among the best nuclear reactors in the world in terms of cost-effectiveness, safety measures and output performance. Figure 7.3 indicates that among lifetime performance for five types of nuclear reactors (over 150 MW), the CANDU has the highest capacity factor to December 31, 1992. In terms of lifetime performance for nuclear reactors over 500 MW worldwide, Canada's CANDU reactors comprised five of the ten best reactors, and New Brunswick Power's Point Lepreau was ranked first (Figure 7.4).

Surplus Capacity

Electric utilities are empowered with the difficult task of anticipating future electricity demand and ensuring that there are sufficient new generating facilities planned and built to supply the actual need.

During periods of fluctuating demand, such as we are experiencing now, this task provides a significant challenge. On occasion, when new generating facilities are completed and the expected demand does not materialize, the utility is faced with excess generating capacity. In the early-1970s, the construction of new generating stations was initiated mainly on the basis of expectations of continuing rapid growth in electricity demand. However, growth in demand slowed dramatically in the latter part of the decade and some of these newly constructed stations were temporarily surplus to domestic requirements.

In calculating surplus capacity, the generating capability, rather than generating capacity, is normally used. Generating capability measures the expected output of all the available generating facilities in a region at the time of firm peak load. This may differ significantly from the generating capacity measured by the nameplate rating of the equipment.

The variations between generating capability and generating capacity may be caused by a number of factors. These include: water levels in hydro reservoirs, the combined effects of derates and outages, weather effects, and fuel availability.

Reserve Margin

The reserve margin of an electrical system can be defined as the excess of generating capability for in-province use, over the in-province firm peak that occurred during the year, expressed as a percentage of in-province firm peak. Table 7.7 presents the reserve margins of the ten provinces and two territories in 1992. Utilities in the Yukon and Northwest territories have high reserve margins because of the logistics associated with serving remote communities. The extra generators allow the utilities to continue to provide service in the event of equipment failure. Where many communities can be connected together via an electric grid and facilities can be shared, the capacity reserve requirement can be reduced substantially.

Capacity Reserve Requirements

Normal practice in an electrical system is to reserve a certain amount of capacity (expressed as a percentage of firm peak load) to allow for scheduled maintenance, derates or failure of equipment and fluctuations in demand. This portion is usually called the capacity reserve requirement, and it varies from utility to utility, depending on the configuration and requirements of the particular system. Column 4 of Table 7.7 reports the capacity reserve requirement in each province and territory for 1992.

Net Surplus Capacity

Net surplus capacity is defined as the reserve margin less the reserve capacity requirement. Table 7.7 indicates existing net surplus generating capacity by province and for Canada as a whole for 1992. With the exceptions of Prince Edward Island, New Brunswick, Alberta, and British Columbia, all provinces and territories had net surplus capacity by the end of 1992. A weighted average for Canada was about nine per cent. Regions which have low generating capability rely on interconnections with neighbouring electrical systems to meet their peak requirements.

Hydroelectric Potential in Canada

There is still a large amount of undeveloped hydroelectric potential in Canada (Table 7.8). Although much of this is unlikely to be developed due to the remoteness of the sites, the physical difficulty of the terrain or environmental concerns, a significant amount could be developed over the next 25 years.

Tables and figures referred to in this chapter are on the following pages.

Tables & Figures

Table 7.1
Installed Generating Capacity by Fuel Type, 1960-1992

Fuel Type	Installed Generating Capacity						Average Annual Growth Rate	
	1960	1970	1980	1990	1991	1992	1960-1992	1991-1992
	(MW)						(per cent)	
Hydro	18 643	28 298	47 770	58 701	60 251	61 656	3.8	2.3
Thermal	4 392	14 287	28 363	31 174	32 101	32 610	6.5	1.6
Nuclear*	0	240	5 866	13 052	13 052	13 987	-	7.2
Tidal**	0	0	0	20	20	20	-	0.0
Total	**23 035**	**42 825**	**81 999**	**102 947**	**105 424**	**108 273**	**5.0**	**2.7**

* Commercial operation started in 1968.
** Commercial operation started in 1984.
Source: Electric Power Statistics, Volume II, Statistics Canada, catalogue 57-202

Table 7.2
Installed Generating Capacity by Fuel Type and Province, 1992

	Coal	Oil	Natural Gas	Nuclear	Hydro	Other	Total
	(MW)						
Nfld.	0	792	0	0	6650	5	7 447
P.E.I.	0	122	0	0	0	0	122
N.S.	1 332	589	0	0	390	19	2 330
N.B.	418	1 949	0	680	903	87	4 037
Que.	0	1 307	8	685	29 099	5	31 104
Ont.	10 653	2 709	688	12 622	7 191	106	33 969
Man.	369	19	4	0	4 897	23	5 312
Sask.	1 831	22	433	0	836	22	3 144
Alta.	4 861	18	2 032	0	733	336	7 980
B.C.	0	243	1 030	0	10 849	367	12 489
Yukon	0	58	0	0	77	0	135
N.W.T.	0	133	20	0	51	0	204
Canada	**19 464**	**7 961**	**4 215**	**13 987**	**61 676**	**970**	**108 273**

Source: Electric Power Statistics, Volume II, Statistics Canada, catalogue 57-204 and Natural Resources Canada

Table 7.3
Installed Generating Capacity by Province, 1960-1992

	Installed Generating Capacity						Average Annual Growth Rate	
	1960	1970	1980	1990	1991	1992	1960-1992	1991-1992
	(MW)							
Nfld.	314	1 248	7 195	7 462	7 447	7 447	10.4	0.0
P.E.I.	37	77	118	122	122	122	3.9	0.0
N.S.	507	931	2 029	2 156	2 330	2 330	4.9	0.0
N.B.	402	1 201	2 795	3 543	4 037	4 037	7.5	0.0
Quebec	8 920	14 047	20 531	28 873	29 903	31 104	4.0	4.0
Ontario	7 109	13 700	25 796	32 733	33 034	33 969	5.0	2.8
Manitoba	1 043	1 794	4 142	4 414	4 913	5 312	5.2	8.1
Sask.	761	1 533	2 340	2 846	2 844	3 144	4.5	10.5
Alberta	915	2 674	5 807	7 976	7 980	7 980	7.2	0.0
B.C.	2 963	5 473	10 525	12 497	12 489	12 489	4.8	0.0
Yukon	31	58	94	126	130	135	4.7	3.8
N.W.T.	33	89	180	199	195	204	5.9	4.6
Canada	**23 035**	**42 825**	**81 999***	**102 947**	**105 424**	**108 273**	**5.0**	**2.7**

* Includes confidential data, not available by province.
Source: Electric Power Statistics, Volume II, Statistics Canada, catalogue 57-202

Table 7.4
Canada's Largest Hydro Stations, 1992

Rank	Name	Province	Rated Capacity (MW)	Year of Initial Operation
1	Churchill Falls	Newfoundland	5 429	1971
2	La Grande 2	Quebec	5 328	1979
3	La Grande 4	Quebec	2 651	1984
4	Gordon M. Shrum	B.C.	2 416	1968
5	La Grande 3	Quebec	2 304	1982
6	Revelstoke	B.C.	1 843	1984
7	Mica	B.C.	1 736	1976
8	Beauharnois	Quebec	1 653	1932
9	Manic 5	Quebec	1 351	1970
10	Sir Adam Beck 2	Ontario	1 224	1954

Source: Electric Power Statistics,Volume III, Statistics Canada, catalogue 57-206, 1991

Table 7.5
Canada's Largest Conventional Thermal Stations, 1992

Rank	Name	Fuel Type	Province	Rated Capacity(MW)	Year of Initial Operation
1	Nanticoke	coal	Ontario	4 096	1973
2	Lakeview	coal	Ontario	2 400	1962
3	Lennox	oil	Ontario	2 200	1976
4	Sundance	coal	Alberta	2 200	1970
5	Lambton	coal	Ontario	2 040	1969
6	Richard L. Hearn	coal	Ontario	1 200	1951
7	Coleson Cove	oil	New Brunswick	1 050	1976
8	Burrard	natural gas	British Columbia	913	1962
9	Boundary Dam	coal	Saskatchewan	875	1959
10	Keephills	coal	Alberta	806	1983

Source: Electric Power Statistics, Volume III, Statistics Canada, catalogue 57-206, 1991

Table 7.6
Commercial Nuclear Power Plants in Canada, 1992

Rank	Plant Name	Province	Rated Net Capacity (MW)	Commissioning Date
1	Pickering A1	Ontario	515	1971
2	Pickering A2	Ontario	515	1971
3	Pickering A3	Ontario	515	1972
4	Pickering A4	Ontario	515	1973
5	Bruce A1	Ontario	769	1977
6	Bruce A2	Ontario	769	1977
7	Bruce A3	Ontario	769	1978
8	Bruce A4	Ontario	769	1979
9	Point Lepreau 1	New Brunswick	635	1983
10	Pickering B5	Ontario	516	1983
11	Gentilly 2	Quebec	638	1983
12	Pickering B6	Ontario	516	1984
13	Bruce B6	Ontario	837	1984
14	Pickering B7	Ontario	516	1985
15	Bruce B5	Ontario	860	1985
16	Pickering B8	Ontario	516	1986
17	Bruce B7	Ontario	860	1986
18	Bruce B8	Ontario	837	1987
19	Darlington 2	Ontario	881	1990
20	Darlington 1	Ontario	881	1992

Source: Electricity Branch, Natural Resources Canada

Table 7.7
Surplus Capacity in Canada, 1992

	Net Generating Capability for In-Province Use (1)	In-Province Firm Peak (2)	Reserve Margin (3)= ((1)-(2)) / (2)	Capacity Reserve Requirement (4)*	Net Surplus Capacity (5)=(3)-(4)
	(MW)			(per cent)	
Nfld.**	3 061	1 826	68	17	51
P.E.I.	159	138	15	15	0
N.S.	2 237	1 821	23	20	3
N.B.	3 151	2 708	16	20	-4
Quebec	35 712	30 449	17	10	7
Ontario	32 160	23 027	40	24	16
Manitoba	4 959	3 401	46	15	31
Sask.	3 031	2 455	24	15	9
Alberta	8 220	6 758	22	22	0
B.C.	11 074	10 064	10	15	-5
Yukon	135	87	55	19	36
N.W.T.	180	102	77	30	47
Canada	**104 079**	**82 836**	**26**	**17**	**9**

*Expressed as a percentage of in-province firm peak.
**Includes Labrador.

Source: Electric Power Statistics, Volume I, Statistics Canada, catalogue 57-204

Table 7.8
Hydroelectric Capacity in Canada, 1992

Province/Territory	In-Operation and Under Construction	Remaining Potential Gross*	Identified**	Planning***
		(MW)		
Newfoundland	6 656	5 201	4 623	2 555
Prince Edward Island	0	0	0	0
Nova Scotia	390	8 499	8 499	0
New Brunswick	903	940	600	440
Quebec	32 228	68 497	37 055	8 519
Ontario	7 217	12 385	12 385	4 008
Manitoba	4 897	8 360	5 260	5 260
Saskatchewan	836	2 189	935	870
Alberta	733	18 813	9 762	1 923
British Columbia	10 849	33 137	18 168	10 538
Yukon	77	18 583	13 701	350
Northwest Territories	53	9 229	9 201	2 473
Canada	**64 839**	**185 833**	**120 189**	**36 936**

* Gross Potential -- The total gross resource that could be developed if there were no technical, economic or environmental constraints (excludes sites already developed or under construction).

** Identified Potential -- Gross potential less sites that may not be developed for technical reasons.

*** Planning Potential -- Identified potential less sites that may not be developed for environmental or economic reasons. The planning potential thus comprises all those sites that are considered to be likely candidates for future development.

Source: Canadian electrical utilities and Natural Resources Canada

Figure 7.1 Installed Generating Capacity by Fuel Type

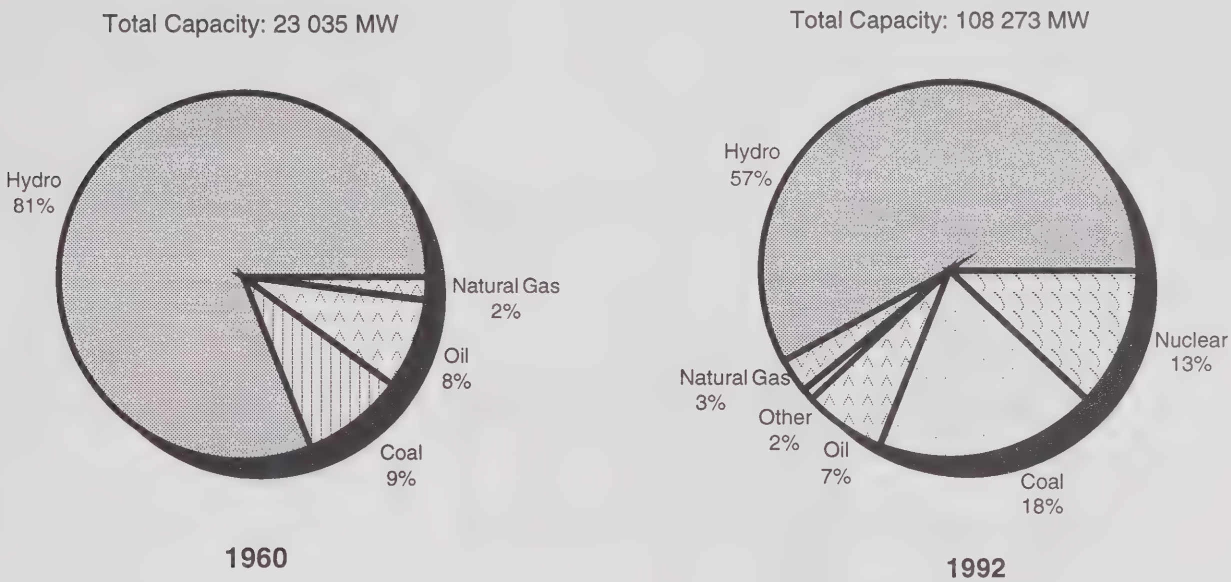


Figure 7.2 Installed Generating Capacity by Region

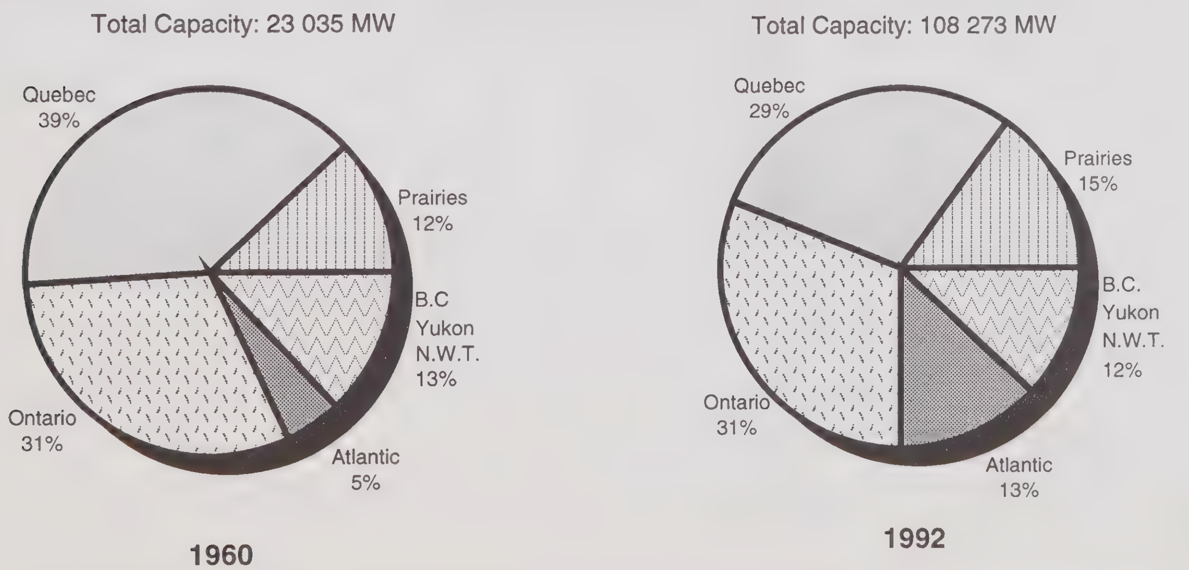
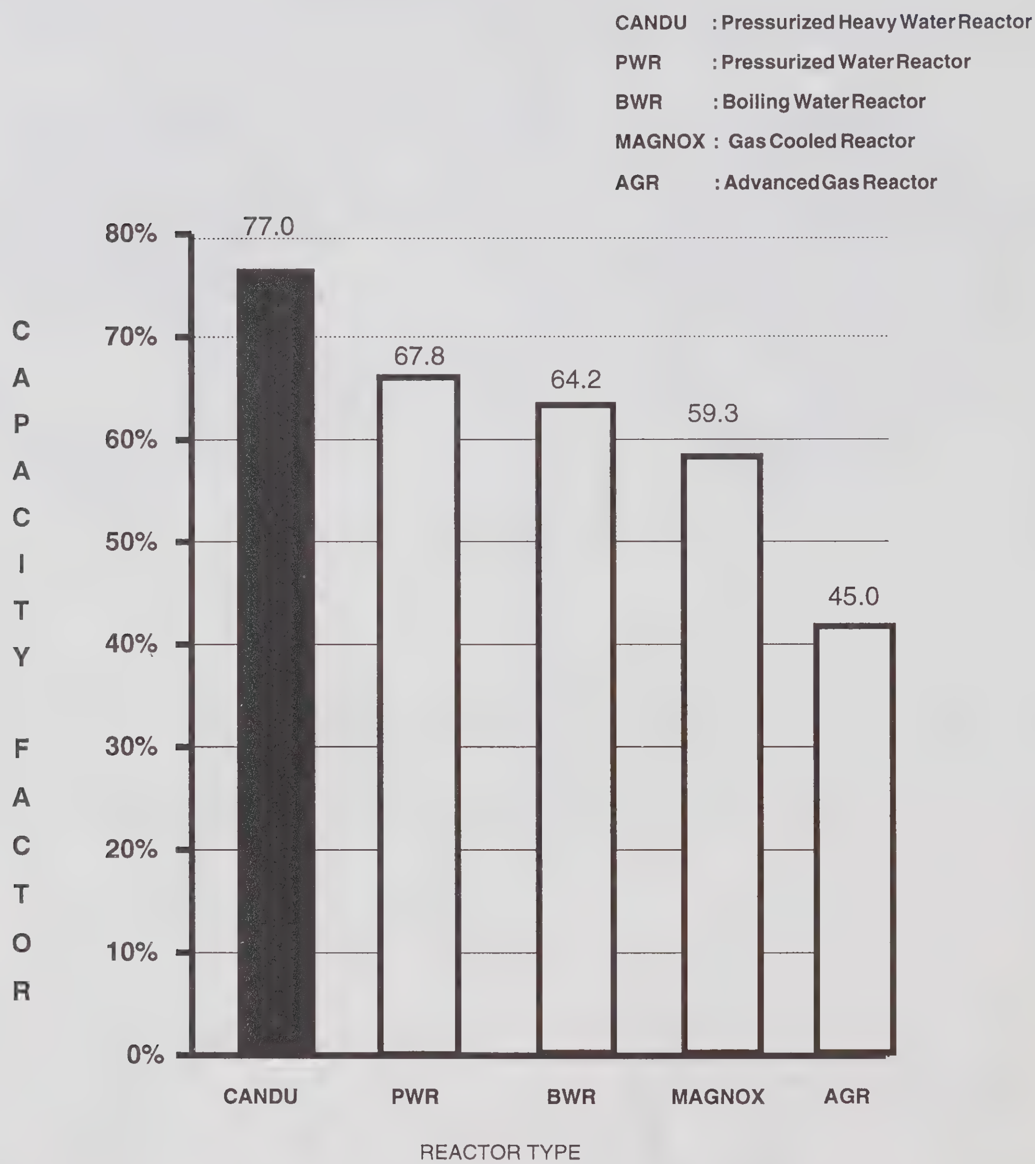


Figure 7.3 Nuclear Reactor Performance Worldwide by Type*

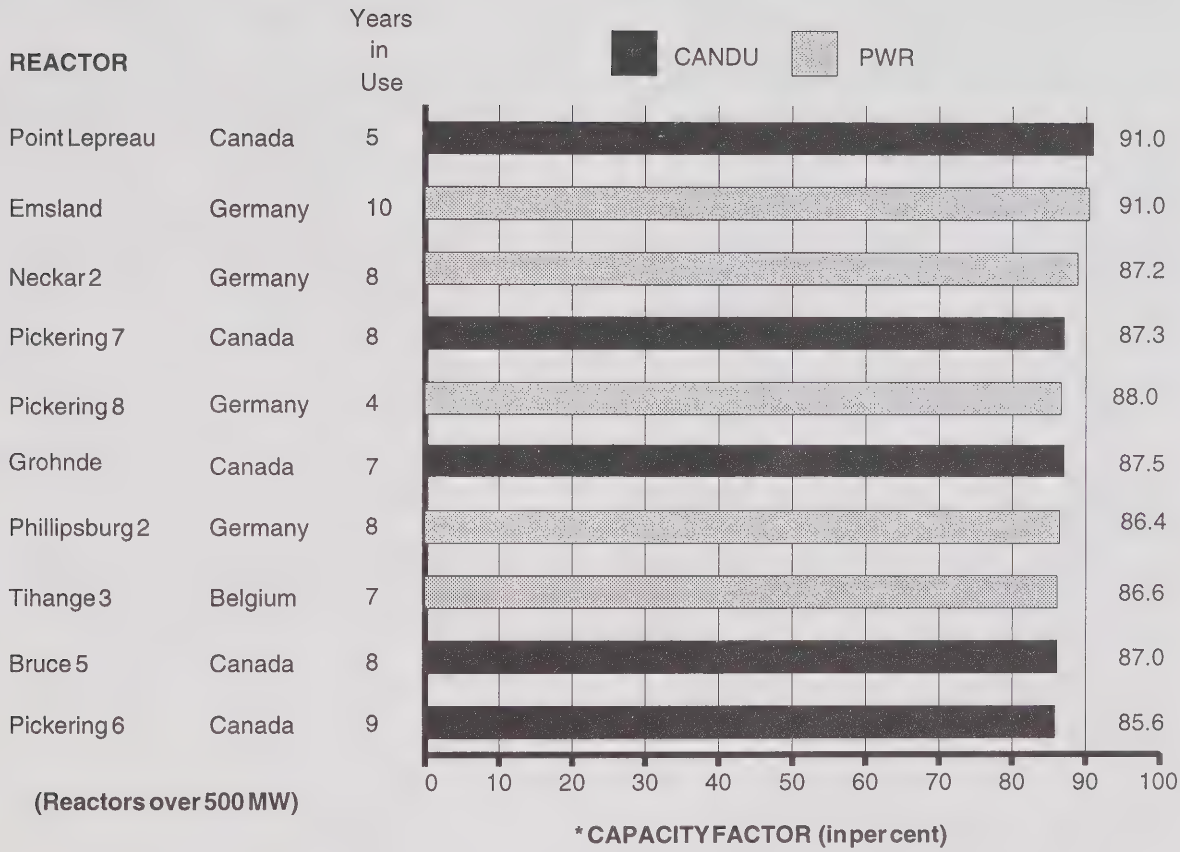


Reactors > 150 MW

* Lifetime to end of December 31, 1992

Source: World Nuclear Industry Handbook 1993 and Atomic Energy of Canada Ltd.

Figure 7.4 World Nuclear Reactor Performance to December 31, 1992



$$\text{*Capacity factor} = \frac{\text{actual electricity generation}}{\text{perfect electricity generation}}$$

Source: Nuclear Engineering International, April 1993

Chapter 8

Electricity Trade

International Trade

Electricity trade between Canada and the United States dates back to the beginning of the century. In 1901, the first electric power transmission line between the two countries was built at Niagara Falls which enabled abundant Canadian hydroelectric power to be marketed in the United States. This historical event set the stage for continued electricity exchanges between the two countries in a climate of international cooperation and coordination. During the early years, Canadian electricity exports to the U.S. were usually in the form of long-term firm power sales contracts because Canada needed the export contracts to finance construction of hydroelectric plants. Both Canadian and U.S. companies invested in generating capacity built in Canada for export.

Since 1921, electricity trade has been in Canada's favour in terms of quantity. Canada's net exports grew substantially from the early-1970's reaching a peak of 45 TWh in 1987, largely due to the high cost of thermal production in the United States.

Electricity trade between the United States and Canada is mainly attributed to the following:

- differences in the natural resources of the two countries have a significant impact on the level of trade. For instance, many Canadian provinces, such as Newfoundland, Quebec, Manitoba, and British Columbia have an abundance of hydroelectric resources that can be substituted for U.S. generation from fossil fuels;

- cost differences stimulate the selling of Canadian power to U.S. markets for profit;

- electric utilities benefit from the purchase of less costly Canadian supplies; and

- electrical energy supply systems in the U.S. and Canada have differences in seasonal peak demands, which makes surplus energy exchanges possible. While all electrical systems in Canada have their peak demand in winter, all electrical systems in the United States have their peak in summer.

Electricity trade between the United States and Canada provides a wide variety of benefits to consumers and electric utilities in both countries. These benefits include:

- *rate reduction:* electric utilities normally use export revenues to reduce their revenue requirements, which, in turn, reduces rate increases;

- *surplus energy sales:* the existence of secondary markets, including storage, to utilize energy from renewable resources that would otherwise be wasted;

- *economy interchange:* the interchange of electricity between two utilities which results in a reduction of production costs;

- *diversity exchange:* non-coincident peak loads which allow utilities to share generation and realize economic benefits;

- *reserve sharing:* agreements for mutual generation support so that new power plant requirements are decreased; and

- *coordination of planning and operation:* cooperation between utilities, mainly in generation facility planning, operation, and maintenance, to reduce investment requirements and distribute maintenance outages so that system operations are optimized.

In 1992, electricity exports to the United States increased 32 per cent over 1991, reaching about

26 224 GWh, while imports declined 4 per cent to 1836 GWh. Exports accounted for 5.2 per cent of Canada's total electricity generation in 1992, up from 4.1 per cent in 1991. Export revenue also increased significantly by 26 per cent, from $558 million in 1991 to $708 million in 1992, while import costs increased from $71 million in 1991 to $84 million in 1992.

Export increases in 1992, occurred mainly in Quebec, Manitoba, and British Columbia due to improved water flows in these provinces. The addition of the remaining three units at Manitoba Hydro's Limestone generating station also contributed to the increase in exports.

Ontario Hydro's nuclear stations did not perform well in 1992, output from nuclear generation dropped about 6 per cent, and therefore exports to the United States declined by 11 per cent.

As usual, interruptible exports were the main type of electricity exports to the United States, accounting for 54 per cent of the total in 1992, compared with 46 per cent for the firm export share. However, firm exports accounted for a greater share of the total export revenue; 56 per cent compared with 44 per cent for interruptible exports in 1992.

Because of relatively low fuel costs in the United States, both average firm and interruptible export revenues continued to fall in 1992. Average firm export revenues dropped 8 per cent to 32.6 mills per kWh in 1992, from 35.3 mills per kWh in 1991, while average interruptible export revenues dropped 1 per cent, from 22.4 mills per kWh in 1991 to 22.1 mills per kWh in 1992.

Hydro generated electricity continued to be the main source of Canada's electricity exports, accounting for 76 per cent in 1992 compared to 72 per cent in 1991. Nuclear power declined from 11 per cent in 1991 to 5 per cent in 1992, while natural gas was up from 2 per cent to 8 per cent during the same period. Coal-fired and oil-fired sources of electricity exports were reduced slightly to 9 per cent and 2 per cent, respectively.

U.S. imports of Canadian electricity, as a percentage of total electrical energy demand in the United States, increased slightly from 0.7 per cent in 1991 to 0.9 per cent in 1992. However, U.S. dependence on Canadian exports was higher in certain regions. Exports to New England accounted for 8 per cent of the region's total electricity consumption in 1992. The corresponding ratio was 4 per cent for the Midwest and 2 per cent each for New York, the Pacific Northwest, California, and the Southern Nevada region.

Electricity Trade and the Economy

The export of electricity is an important aspect of Canada's foreign trade. While total electricity export revenue accounted for only 0.4 per cent of total merchandise exports and 4.2 per cent of total energy exports in 1992, net electricity export revenue accounted for 4.4 per cent of Canada's balance of trade and 6.1 per cent of Canada's total energy trade balance in 1992. Canadian energy trade by fuel type during the period 1975-92 is reported in Table 8.11.

Interprovincial Trade

In Canada, provincial electric utilities trade electricity across provincial borders for the same reasons that trade occurs between Canada and the United States: to reduce costs, maximize profits, and mitigate emergencies. Electric utilities import electricity when imports are less expensive than their own production. Similarly, electric utilities export power when they can both meet domestic demand and maximize profits by marketing additional power to outside buyers.

Although Canadian interprovincial electricity trade has consistently been greater than that between Canada and the United States since 1975, it is mainly dominated by the Churchill Falls power contract signed between Newfoundland and Quebec. The Churchill Falls hydro project was built by Hydro-Québec, however, Hydro-Québec only has a minority interest in the power plant. The Churchill Falls (Labrador) Corporation Limited operates the power plant, which began producing electricity in 1972. Under the power contract, about 90 per cent of the Churchill Falls production is sold to Quebec. During the past 10 years, electrical energy sold to Quebec from Churchill Falls accounted for about 66 per cent of Canada's total interprovincial electricity trade.

Interprovincial electricity transfers during the period 1983-92 are summarized in Table 8.13. More information on exports and imports by province is provided in Figure 8.1 and Table A5 in Appendix A.

Tables and figures referred to in this chapter are on the following pages.

Tables & Figures

Table 8.1
Canada-U.S. Electricity Trade, 1960-1992

	Exports* (GWh) (1)	Exports as a Percentage of Net Generation (2)	Export Revenues ($million) (3)	Imports* (GWh) (4)	Imports as a Percentage of Total Disposal** (5)	Import Cost ($million) (6)	Net Exports (GWh) (7)=(1)-(4)	Net Exports $Million (8)=(3)-(6)
1960	5 496	4.8	14	357	0.3	1	5 139	13
1965	3 684	2.6	8	3 575	2.5	3	109	5
1970	5 631	2.8	32	3 245	1.6	9	2 386	23
1975	11 409	4.2	104	3 972	1.5	3	7 819	102
1980	28 224	7.7	773	168	0.1	3	28 056	791
1985	41 441	9.3	1 425	231	0.1	9	41 210	1 416
1987	45 359	9.4	1 211	536	0.1	12	44 823	1 199
1988	29 729	6.1	880	2 853	0.6	63	26 879	817
1989	18 462	3.8	661	8 747	1.9	292	9 715	369
1990	16 494	3.5	547	15 543	3.5	556	951	(9)
1991	19 828	4.1	558	1 905	0.4	71	17 923	487
1992	26 224	5.2	708	1 836	0.4	84	24 388	625

* Exports and imports prior to 1977 include service exchanges.
** Total disposal refers to total electricity available for domestic consumption.
Source: Electric Power Statistics, Volume II, Catalogue 57-202, Statistics Canada and Natural Resources Canada

Table 8.2
Provincial Shares of Canadian Electricity Exports, 1960-1992*

Year	New Brunswick	Quebec	Ontario	Manitoba	Sask.	British Columbia	Canada
1960	3.0	10.4	86.6	0.0	0.0	0.0	100.0
1965	6.4	1.3	84.0	0.0	0.0	8.3	100.0
1970	13.4	0.9	63.9	5.2	0.0	16.6	100.0
1975	14.2	8.0	42.5	10.3	0.0	25.0	100.0
1980	13.8	28.7	40.5	11.8	0.0	5.2	100.0
1985	14.8	23.1	22.5	13.6	0.3	25.7	100.0
1989	24.1	30.9	14.7	6.6	0.1	23.6	100.0
1990	25.4	30.9	4.5	11.7	0.3	27.2	100.0
1991	15.6	29.2	11.7	16.7	0.3	26.6	100.0
1992	6.6	33.7	7.8	23.1	0.3	28.5	100.0

* Excludes non-cash exchanges
Source: National Energy Board

Table 8.3
Firm and Interruptible Exports by Province, 1992*

	Firm	Interruptible	Firm	Interruptible
	(GWh)		(per cent)	
New Brunswick	1 247	438	72	28
Quebec	7 012	1 814	79	21
Ontario	265	1 791	13	87
Manitoba	1 138	4 920	19	81
Saskatchewan	0	79	0	100
British Columbia	2 506	4 969	34	66
Canada	**12 168**	**14 056**	**46**	**54**

* Exchanges are excluded

Source: National Energy Board

Table 8.4
Electricity Exports to the United States by Type, 1960-1992

	Quantity (GWh)		Revenue ($1000)		Quantity Share (%)		Revenue Share (%)	
	Firm*	Interruptible**	Firm	Interruptible	Firm	Interruptible	Firm	Interruptible
1960	1 040	4 456	4 328	10 023	19	81	30	70
1965	635	3 049	4 261	3 322	17	83	56	44
1970	984	4 648	6 828	25 309	18	82	21	79
1975	2 375	9 034	20 382	84 488	21	79	19	81
1980	7 232	20 992	156 731	636 760	26	74	20	80
1985	12 305	291 365	547 109	877 657	30	70	38	62
1989	8 378	10 084	350 666	310 692	45	55	53	47
1990	8 701	7 794	346 513	200 147	53	47	63	37
1991	8 789	11 039	310 049	247 484	44	56	56	44
1992	12 168	14 056	397 184	311 070	46	54	56	44

* Electrical energy intended to be available at all times during the period of the agreement for its sale.

** Energy made available under an agreement that permits curtailment or interruption of delivery at the option of the supplier.

Source : National Energy Board

Table 8.5
Average Export Revenues, 1960-1992

Year	Firm	Interruptible	Total
	(mills/kWh)		
1960	4.2	2.3	2.6
1965	6.7	1.1	2.1
1970	6.9	5.5	5.7
1975	8.6	9.4	9.2
1980	21.7	30.3	28.1
1985	44.5	30.1	34.4
1989	41.9	30.8	35.8
1990	39.8	25.7	33.1
1991	35.3	22.4	28.1
1992	32.6	22.1	27.0

Source: Calculated from Table 8.4

Table 8.6
Electricity Exports and Revenues by Province, 1991-1992*

	Quantity (GWh)			Revenue (million $)			Average Revenue (mills/kWh)		
	1991	1992	% Change	1991	1992	% Change	1991	1992	% Change
N.B.	3 086	1 730	-44	145.41	88.45	-39	47.1	51.1	8
Que.	5 784	8 827	53	169.51	269.22	59	29.3	30.5	4
Ont.	2 314	2 056	-11	65.21	59.23	-9	28.2	28.8	2
Man.	3 316	6 058	83	57.31	95.70	67	17.3	15.8	-9
Sask.	59	79	36	0.69	1.70	148	11.7	21.4	83
B.C.	5 269	7 474	42	119.40	193.96	62	22.7	26.0	15
Canada	**19 828**	**26 224**	**32**	**557.50**	**708.25**	**27**	**28.1**	**27.0**	**-4**

* Excludes non-cash exchanges.
Source: National Energy Board

Table 8.7
Average Export Revenues by Province, 1991 vs 1992

	Firm		Interruptible	
	1991	1992	1991	1992
	(mills/kWh)			
New Brunswick	53.3	58.3	30.9	32.5
Quebec	30.2	30.5	26.4	30.5
Ontario	30.2	39.7	27.9	27.2
Manitoba	22.4	25.1	15.6	13.7
Saskatchewan	-	-	11.7	21.4
British Columbia	29.5	28.5	20.9	24.7
Canada	**35.3**	**32.6**	**22.4**	**22.1**

Source: "Canada-U.S. Electricity Trade Report", Natural Resources Canada

Table 8.8
Generation Sources of Canadian Electricity Exports, 1975-1992

	Hydro	Imported Coal	Imported Oil	Domestic Coal/Oil	Nuclear	Natural Gas	Total
	(GWh)						
1975	5 724	4 838	494	353	0	-	11 409
1976	6 973	4 323	1 206	302	0	-	12 804
1977	7 926	8 514	2 961	555	0	-	19 957
1978	7 290	10 476	2 260	411	0	-	20 437
1979	15 213	11 587	3 354	128	177	-	30 458
1980	14 135	10 599	2 867	593	30	-	28 224
1981	21 182	10 901	1 940	665	42	-	34 730
1982	20 114	10 315	1 959	502	96	-	32 986
1983	21 978	11 704	1 201	519	1 856	-	37 258
1984	22 807	10 582	1 552	711	1 911	-	37 563
1985	28 836	8 245	1 157	956	2 247	-	41 441
1986	25 727	5 389	846	825	2 484	-	35 271
1987	34 065	7 575	1 270	408	2 041	-	45 359
1988	19 621	4 531	1 393	2 033	2 151	-	29 729
1989	9 054	1 452	1 089	2 214	2 032	2 621	18 462
1990	11 299	266	885	1 244	2 054	796	16 494
1991	14 415	1 546	610	697	2 172	388	19 828
1992	20 121	1 339	416	1 083	1 200	2 065	26 224

Source: Compiled from National Energy Board Statistics

Table 8.9
Energy Sources of Electricity Exports, 1992

	Natural Gas	Oil	Coal	Nuclear	Hydro	Other*	Total	Energy Exported
				(per cent)				(GWh)
New Brunswick	-	24	27	49	0	0	100	1 730
Quebec	-	-	-	-	100	-	100	8 827
Ontario	-	4	65	24	3	3	100	2 056
Manitoba	-	-	-	-	100	-	100	6 058
Saskatchewan	-	-	100	-	-	-	100	79
British Columbia	28	-	12	-	60	-	100	7 474
Canada	**8**	**2**	**9**	**5**	**76**	**0**	**100**	**26 224**

* Refers to U.S. electricity imports that are subsequently exported.
Source: Natural Resources Canada

Table 8.10
Exporting Provinces and Importing Markets, 1992*

Exporting Province	Importing Market	Quantity (MWh)	Value ($1000)
New Brunswick	Maine	972 636	41 880
	Massachusetts	757 210	46 566
Quebec	Maine	918	66
	Vermont	1 785 155	77 061
	New England (NEPOOL)**	5 413 912	119 407
	New York	1 626 684	72 685
Ontario	Vermont	430	8
	New York	1 691 848	45 650
	Michigan	83 474	1 697
	Minnesota	26 426	1 635
Manitoba	Minnesota	3 876 447	62 156
	North Dakota	602 677	9 616
Saskatchewan	North Dakota	79 485	1 697
British Columbia	Washingon	5 273 272	140 114
	Oregon	890 254	22 402
	Idaho	263 031	6 839
	Montana	17 091	341
	California	1 009 856	23 551
	Nevada	20 448	659
	Alaska	530	57
Canada	**United States**	**24 391 784**	**674 086**

* Excludes non-cash exchanges.
** The New England Power Pool (NEPOOL) coordinates electrical service to member utilities in New Hampshire, Maine, Vermont, Massachusetts, Conneticut, and Rhode Island.
Source: National Energy Board

Table 8.11
Canadian Energy Trade, 1975-1992

	Oil	Natural Gas	Coal	Electricity	Uranium	Total Energy
			($ million)			
1975						
Exports	3 684	1 092	483	104	133	5 496
Imports	3 508	8	643	13	12	4 184
Balance	**176**	**1 084**	**-160**	**91**	**121**	**1 312**
1980						
Exports	5 352	3 984	824	773	870	11 803
Imports	7 545	0	882	3	17	8 447
Balance	**-2 193**	**3 984**	**-58**	**770**	**853**	**3 356**
1985						
Exports	9 379	4 011	2 041	1 425	825	17 681
Imports	5 315	0	1 077	8	28	6 428
Balance	**4 064**	**4 011**	**964**	**1 417**	**797**	**11 253**
1988						
Export	6 338	2 954	2 063	881	585	12 821
Imports	4 341	0	828	63	75	5 307
Balance	**1 997**	**2 954**	**1 235**	**818**	**510**	**7 514**
1989						
Exports	6 723	3 017	2 201	659	456	13 056
Imports	5 408	0	777	297	109	6 591
Balance	**1 315**	**3 017**	**1 424**	**362**	**347**	**6 465**
1990						
Exports	9 298	3 280	2 276	539	315	15 708
Imports	7 384	0	684	568	105	8 741
Balance	**1 914**	**3 280**	**1 592**	**-29**	**210**	**6 967**
1991						
Exports	9 607	3 512	2 206	558	290	16 169
Imports	6 104	33	523	71	62	6 793
Balance	**3 503**	**3 479**	**1 683**	**487**	**228**	**9 376**
1992						
Exports	9 740	4 361	1 884	708	306	16 999
Imports	5 820	50	647	84	114	6 715
Balance	**3 920**	**4 311**	**1 237**	**624**	**192**	**10 284**

Source: Statistics Canada, Exports by Commodities (65-004) and Imports by Commodities (65-007)

Table 8.12
Annual Canadian Interprovincial Electricity Trade, 1960-1992

Year	Total Canadian Generation (GWh)	Delivered to other Provinces (GWh)		Percentage of Interprovincial Transfers to Total Generation	
		With Churchill Falls*	Without Churchill Falls	With Churchill Falls	Without Churchill Falls
1960	114 378	7 108	7 108	6.2	6.2
1965	144 274	6 230	6 230	4.3	4.3
1970	204 723	8 137	8 137	4.0	4.0
1975	273 392	49 198	19 684	18.0	7.2
1980	367 306	52 709	14 965	14.4	4.1
1985	446 413	51 663	19 917	11.6	4.5
1989	482 158	36 176	11 809	7.5	2.4
1990	465 967	37 499	11 335	8.0	2.4
1991	489 227	38 530	12 164	7.9	2.5
1992	501 523	41 586	15 601	8.3	3.1

* The Churchill Falls project was completed in 1974 (the initial operation started in 1971). Over 90% of the energy it produces flows into Quebec under a contract that terminates in the year 2041.

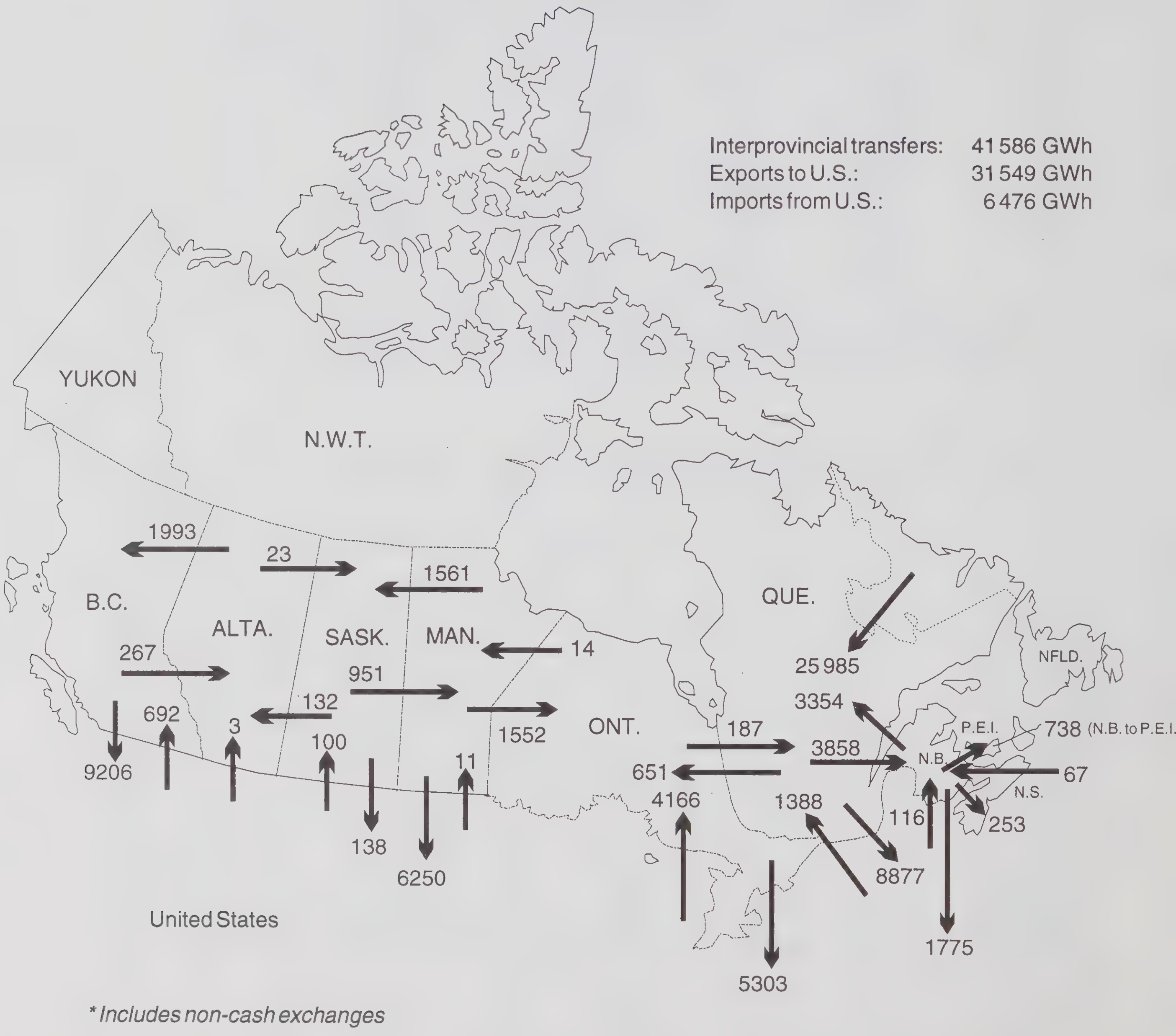
Source: Natural Resources Canada

Table 8.13
Interprovincial Electricity Trade by Destination, 1983-1992

	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
	(GWh)									
Nfld. to Que.	31 229	36 012	31 836	30 695	30 393	30 727	24 367	26 164	26 366	25 985
N.S to N.B.	121	271	190	71	82	166	341	116	50	67
N.B. to N.S.	737	303	360	620	659	186	441	365	444	253
N. B. to P.E.I.	520	550	585	610	483	486	622	672	690	738
N.B. to Que.	1	0	2	0	20	309	951	1 116	1 408	3 354
Que. to N. B.	3 971	4 342	5 951	7 204	6 840	2 690	1 966	2 659	3 383	3 858
Que. to Ont.	5 378	7 364	8 685	7 292	5 942	2 289	1 032	690	729	651
Ont. to Que.	52	68	106	17	15	43	80	134	109	187
Ont. to Man.	13	2	0	5	3	22	11	6	0	14
Man. to Ont.	955	940	959	735	1 050	538	1 303	1 636	1 482	1 552
Man. to Sask.	1 610	1 593	1 530	1 211	1 262	1 370	1 171	1 058	1 152	1 561
Sask. to Man.	1 209	1 299	1 240	1 076	1 220	1 109	1 115	1 047	975	951
Sask. to Alta.	2	3	0	0	0	0	15	39	23	132
Alta. to Sask.	4	0	0	0	0	0	42	94	116	23
Alta. to B.C.	46	259	182	617	710	1 218	2477	1 242	948	1 993
B.C. to Alta.	163	296	37	553	521	364	242	461	655	267
Total	**46 007**	**54 302**	**51 663**	**50 706**	**49201**	**41 517**	**36 176**	**37 499**	**38 530**	**41 586**

Source: Statistics Canada

Figure 8.1 Electricity Trade, 1992 (GWh)*



*Includes non-cash exchanges

Chapter 9

Transmission

Transmission Circuit Length

The electric power system in Canada consists of three interrelated functions: the generating system which produces the power; the transmission network which conducts the flow of power from the point of generation to the point of distribution; and the distribution system which delivers the power to consumers. In most provinces, all three of these interrelated functions are provided by one or a few major electric utilities.

The electrical transmission network in Canada has evolved from a simple system designed to serve customers at the local level into a highly complex interconnected system. In the early years of the 20th century, relatively small generating plants were situated close to the loads which they served, with power transmitted at low voltages under 60-kV.

Fast growth in electricity demand throughout the early 20th century brought forth successively larger power plants that were constructed farther away from load centres and nearer to abundant water resources. Transmission systems were used to distribute power to the geographically dispersed load areas. The integrated electric power system, coupled with the growth in interconnection of previously isolated power networks, led to the development of a new generation of higher voltage transmission in the range of 100 to 230-kV.

After World War II, in response to rapid electrification and installation of larger hydro and thermal generating stations, much higher voltages of transmission lines, such as 345-kV, 500-kV, 735-kV, and ±450(DC) were introduced into commercial operation.

Total circuit length of electrical transmission in Canada for lines rated at 50-kV and above, increased by 1088 km in 1992, slightly less than 1353 km in 1991. The total length of Canadian bulk transmission is now 154 604 km, with the largest share (32 per cent) being in the 100-kV to 149-kV range. Another 25 per cent is in the 200-kV to 299-kV range, while 21 per cent is between 50-kV and 99-kV (Table 9.1).

Newfoundland and Quebec are the only two provinces with transmission lines over 600-kV. Newfoundland has three 735-kV lines wheeling power from its Churchill Falls hydro station in Labrador to Quebec City and Montreal, and Quebec has five 735-kV lines and one ±450-kV high-voltage direct current (HVDC) line delivering power from three hydro stations in the James Bay region to Montreal and the United States. Quebec also has a 765-kV line used mainly for export purposes, which delivers power from Chateauguay to the State of New York.

In 1992, transmission line additions within the provinces were found mainly in Ontario, Nova Scotia, Saskatchewan, and New Brunswick. Ontario Hydro increased its 500-kV line by 249 km from Lennox to Hawthorne, and from Nanticoke to Clairville. Ontario Hydro also extended its 230-kV line by 46 km from Kidd Creek Metsite to Ansoville. Nova Scotia Power increased its system by 288 km with the additions of one 345-kV line from Hopewell to Woodbine and two 230-kV lines from Woodbine to Point Aconi and River Ryan. SaskPower increased its 230-kV line by 273 km from the newly completed Shand station to Peebles, and from Brada to Lloydminister. New Brunswick Power completed its three 345-kV lines in 1992 and added 212 km to its system, linking Salisbury to Newcastle, and Newcastle to Bathurst.

Presently, there are only 7 in-province transmission lines under construction ranging from 230-kV to 735-kV, with a total circuit length of about 1586 km. Hydro-Québec is building a 735-kV line linking Chissibi to Jacques Cartier,

with a total circuit length of 9655 km. Hydro-Québec is also building three 315-kV lines in the Phase II of the James Bay area, linking Brisay, Laforge 2, and Nikamo, and Laforge 1 and Nikamo.

Ontario Hydro is in the process of adding two more 500-kV lines. One will connect the Lennox oil-fired station (near Kingston) with Bowmanville, and the other one is linking Cherrywood and Chaireville.

In Saskatchewan, another 230-kV line presently under construction will connect Condie with Queen Elizabeth. The total circuit length for this line will be 230 km.

Interprovincial Transmission

To facilitate energy exchanges and enhance the reliability of electrical systems operation, there are now 36 major provincial interconnections, with a total transfer capability of about 10 145 MW (Table 9.2). No provincial interconnection was added in 1992.

Up until 1991, two provincial interconnections were still being planned: one was a 500-kV line linking the Quebec Outaouais with Ottawa, a total circuit length of 51 km, and the other was a 500-kV line from Winnipeg to Dryden, Ontario, with a circuit length of 300 km. The estimated power transfer capability of each was to be about 1200 MW. However, these two lines were cancelled because electricity demand growth in Ontario for 1992 is estimated to be much lower than previously anticipated.

International Transmission

Interconnections play a major role in modern power systems. Most Canadian utilities have both east-west and north-south lines that allow exchanges of power and energy. No international interconnection was completed in 1992.

There are now over 100 international transmission lines in place to provide for Canada's international electricity trade. Although most of these lines are quite small, there are 37 bulk power interties rated at 69-kV or higher, with a total power transfer capability of 18 900 MW (Table 9.3).

B.C. Hydro is in the process of planning two 230-kV and one 500-kV international transmission lines. The new lines will increase B.C. Hydro's total firm power transfer capability by about 1700 MW. The lines are expected to be in service by 1997 and 2003, respectively. New Brunswick Power is also planning to build a 345-kV line from Lepreau to Orrington of Maine. The transfer capability is estimated to be 600 MW (Table 9.4).

Long-Distance Transmission

Canada is a world leader in long-distance electric power transmission, in both extra-high-voltage (EHV) alternating current and HVDC. A major influence on the development of Canada's expertise in these areas has been the country's abundant water power resources. Early in the century, pioneering efforts in high-voltage transmission resulted in the initial development of hydroelectric power at Niagara Falls to supply the growing needs of communities in southern Ontario. In Quebec, the first 50-kV transmission lines were constructed to bring power from Shawinigan to Montreal.

After the harnessing of major hydroelectric sites close to load centres, it became necessary to develop remote hydroelectric sources in several provinces and to integrate these sources into the power system over long-distance EHV and HVDC transmission lines. In 1965, Hydro-Québec installed the world's first 735-kV class transmission system. This system now extends

over 1100 km from the Churchill Falls development in Labrador to Montreal. A comparable system of about the same distance extends from the James Bay development to Quebec's load centres.

In Manitoba, pioneering work was done under federal financial assistance to develop the ±450-kV HVDC system which now brings hydroelectric power from the Nelson River generating stations to customers in southern Manitoba. Recently, Hydro-Québec built a ±450-kV HVDC line delivering power from La Grande 2 station at Radisson to the United States. Ontario and British Columbia also have extensive EHV systems in the 500-kV class (Figure 9.1).

Such advances in Canadian transmission techniques have provided not only for long-distance bulk transmission, but also for extensive interconnections between neighbouring provinces and between Canada and the United States (Figure 9.2).

Reliability of Electric Service

Reliability of electric service has always been of prime importance to the electrical system. The reliability of supply is reflected in terms of frequency and duration of interruptions (outages) to the customer. The reliability of an electricity supply system, particularly the transmission and distribution segments of the system, is determined by a variety of factors, such as scheduled interruptions, loss of supply, tree contact, lightning, defective equipment, adverse weather, adverse environment, human elements, and other interference. Canada with its vast territory, long and severe winters, and its large hydro-electric plants which are often located far from population centres, is likely to be at a disadvantage compared to countries with smaller geographic areas and greater population density.

In Canada, the most commonly used indices to measure the reliability of electric service are the *System Average Interruption Frequency Index (SAIFI)*, the *System Average Interruption Duration Index (SAIDI)*, and the *Average Interruption Time Per Customer Per Year.*

SAIFI is the average number of interruptions experienced per customer per time unit. It is calculated by dividing the number of customer interruptions observed in a year by the number of customers affected.

SAIDI is the average interruption duration for customers served during a year. It is calculated by dividing the sum of all customer sustained interruption durations during the year by the number of customers served during the year.

The *Average Interruption Time Per Customer Per Year* is the product of SAIFI and SAIDI.

Figure 9.3 provides a comparison of the frequency of supply interruptions per customer per year for 14 major Canadian electricity suppliers in 1992. There is considerable variation in performance across Canada, for example, Maritime Electric Company shows an interruption frequency 11 times higher than the Edmonton figure, and although Ontario Hydro serves electricity in a vast territory under severe weather, its reliability is one of the best in Canada. Hydro-Québec, B.C. Hydro, and Manitoba Hydro are predominately hydroelectric systems, however, the interruption frequency of Hydro-Québec's system is 3.5 times higher than B.C. Hydro and about three times higher than the Manitoba figure.

The average frequency of interruptions for Canada as a whole was 3.1 interruptions per customer per year in 1992. In 1991, a total average for Japan and Australia was 0.35 and 2.6 interruptions per customer per year.

The duration of interruptions is reflected, in part, by how quickly the various electric authorities

correct faults in the system. As was pointed out earlier, many factors will determine the duration of interruptions. Some of these factors such as the severity of storms, fires, and floods will be out of the electricity suppliers' control. As a result, considerable variation in the duration of interruption may be expected from year to year.

Figure 9.4 presents the duration of interruptions for 14 major Canadian electric utilities. As in the case of interruption frequency, the duration of interruptions in Canadian electrical systems varies considerably, ranging from 20 minutes for Edmonton Power to more than two and half hours for Alberta Power. It is interesting to note that both Edmonton Power and Alberta Power serve the same province of Alberta. Edmonton Power's much shorter interruption duration is partially due to the fact that it is a municipal utility serving electricity in a much smaller area with a greater population density than that of Alberta Power.

Of the 14 utilities, Ontario Hydro rates second in having the shortest interruption duration with only 32 minutes. Although Hydro-Québec has a much higher frequency of outages when compared to other Canadian electrical systems, the short duration of its outages in 1992 reflects a quick response time to faults in the system.

As indicated in Figure 9.4, the average customer outage duration in Canada was 74 minutes in 1992. There are no corresponding figures for other countries in the same year. However, compared with other countries' 1991 figures, performance for Canada is quite satisfactory. According to the Australian Bureau of Industry Economics, the average customer duration per interruption was 124 minutes for Australia, 94 minutes for Japan, and 66 minutes for U.S. public utilities.

The product of average interruption frequency and average interruption duration provides an estimate of average interruption time per customer per year. The comparisons summarized in Figure 9.5 indicate that there are significant differences in system performance by province. For instance, the average interruption time per customer per year for Edmonton Power was only 13 minutes, compared with 463 minutes for Maritime Electric Company. This is mainly due to the relatively high frequency of interruptions in Prince Edward Island, where most of their electricity supply comes from New Brunswick Power through an undersea cable.

On average the Canadian systems were relatively higher in interruption frequency and faster in dealing with faults in transmission and distribution. Therefore the average interruption time per customer per year was quite comparable with other countries, about 222 minutes, as reported in Figure 9.5. According to the same Australian source for the 1991 data, the average interruption time per customer per year was 33 minutes for Japan, 208 minutes for rural U.S, and 324 minutes for Australia.

Tables and figures referred to in this chapter are on the following pages.

Tables & Figures

Table 9.1
Transmission Circuit Length in Canada, 1992

	50-99 kV	100-149 kV	150-199 kV	200-299 kV	300-399 kV	400-599 kV	600 kV and up	Total
				(km)				
Nfld.	2 356	1 985	-	2 005	-	-	612	6 958
P.E.I.	390	193	-	-	-	-	-	583
N.S.	2 027	1 703	-	1 236	462	-	-	5 428
N.B.	2 716	2 048	-	629	1 181	-	-	6 574
Quebec	4 150	7 762	2 266	3 810	7 138	1 555	9 955	36 636
Ontario	247	12 318	-	13 963	6	3 027	-	29 561
Manitoba	6 756	4 266	-	4 476	-	2 042	-	17 540
Sask.	4 849	4 534	-	3 250	-	-	-	12 633
Alberta	3 481	9 216	-	5 926	-	215	-	18 838
B.C.	4 996	4 702	316	3 430	403	5 344	-	19 191
Yukon	65	497	-	-	-	-	-	562
N.W.T.	100	-	-	-	-	-	-	100
Canada	**32 133**	**49 224**	**2 582**	**38 725**	**9 190**	**12 183**	**10 567**	**154 604**
	(21%)	(32%)	(2%)	(25%)	(6%)	(8%)	(6%)	(100%)

Source: Statistics Canada Publication 57-202 and Natural Resources Canada

Table 9.2
Provincial Interconnections at Year-End, 1992

Connection	Voltage	Design Capability*
	(kV)	(MW)
British Columbia - Alberta	1 x 500	800
	1 x 138	110
Alberta - Saskatchewan	1 x 230	150
Saskatchewan - Manitoba	3 x 230	400
	2 x 110	100
Manitoba - Ontario	2 x 230	260
	1 x 115	
Ontario - Quebec	4 x 230	1 300
	7 x 120	
Quebec - Newfoundland	3 x 735	5 225
Quebec - New Brunswick	2 x ±80(DC)	700
	2 x 345	
	2 x 230	300
New Brunswick - Nova Scotia	2 x 138	600
	1 x 345	
New Brunswick - P.E.I.	2 x 138	200

* Actual transfer capabiity in practice will be different from design capability.
Source: Natural Resources Canada

Table 9.3
Major Interconnections Between Canada and the United States, 1992*

Province	State	Voltage (kV)	Design Capability*** (MW)
New Brunswick	Maine	1 x 345	600
		1 x 138	60
		5 x 69	155
Quebec	New York	1 x 765	2 300
	New York	2 x 120	300
	Vermont	3 x 120	375
	New Hampshire	±450(DC)	2000
Ontario**	New York	1 x 230	470
		1 x 230	400
		2 x 230	600
		2 x 345	2 300
		2 x 69	132
		2 x 115	200
	Michigan	1 x 230	535
		1 x 230	515
		2 x 345	1 470
	Minnesota	1 x 120	35
Manitoba	North Dakota	1 x 230	150
	Minnesota	1 x 230	175
	Minnesota	1 x 500	1 000
Saskatchewan	North Dakota	1 x 230	150
British Columbia**	Washington	1 x 230	300
		1 x 230	400
		2 x 500	4 300

* 35 MW capacity or over.

** The transfer capability of several lines may not be equal to the mathematical sum of the individual transfer capabilities of the same lines.

*** Actual transfer capability in practice will be different from design capability.

Source: Natural Resources Canada

Table 9.4
Planned International Interconnections

Province/State	Voltage (kV)	Estimated Power transfer Capability (MW)	Completion Date	Status
N.B. - Maine	345	600	1995	Proposed
B.C. -Washington	230	700	1997	Proposed
B.C. -Washington	500	1 000	2003	Proposed

Source: Canadian Electric Utilities

Figure 9.1 Canada's Major Long-Distance Transmission Systems, 1992

Figure 9.2 Major Provincial and International Interconnections, 1992

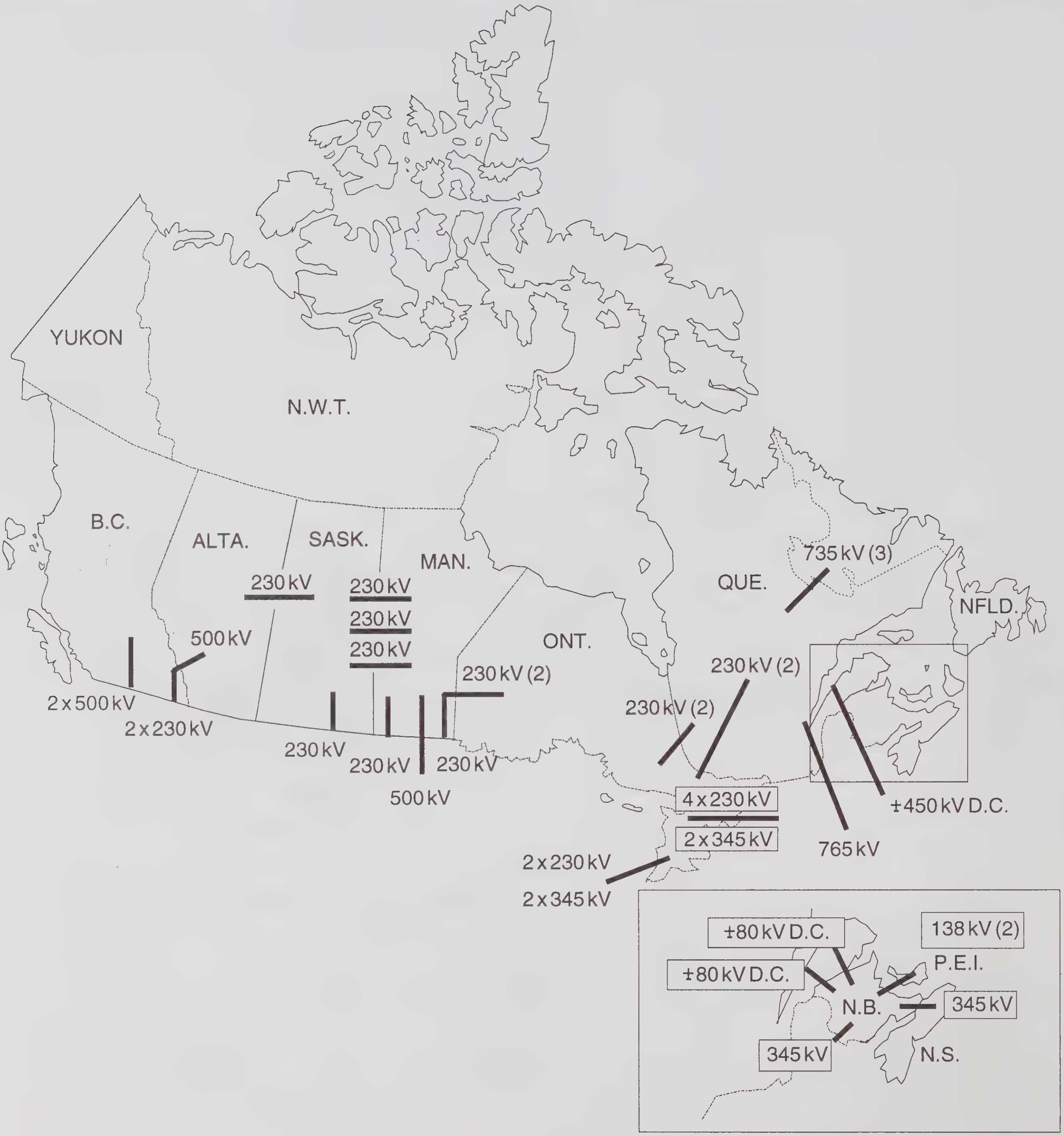


Figure 9.3 System Average Interruption Frequency in Canada

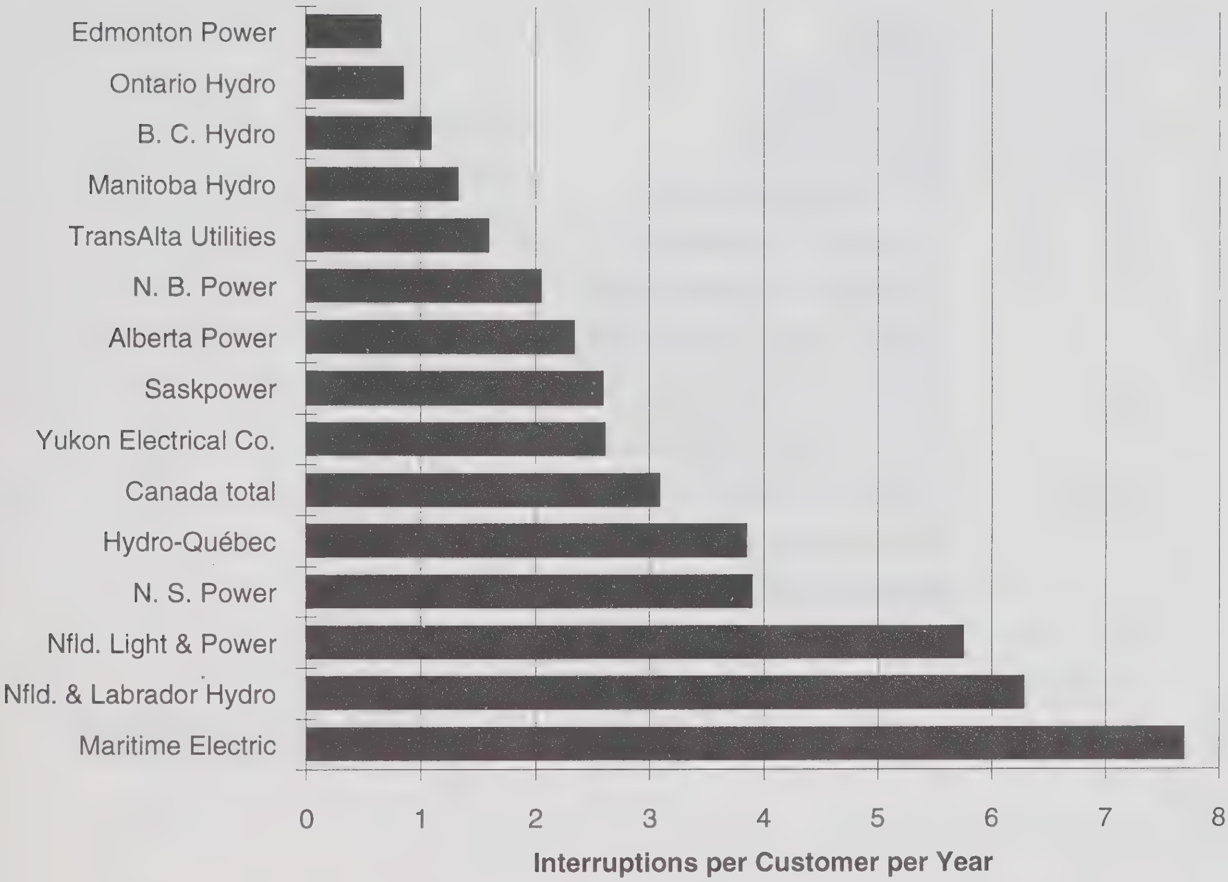


Figure 9.4 System Average Interruption Duration in Canada

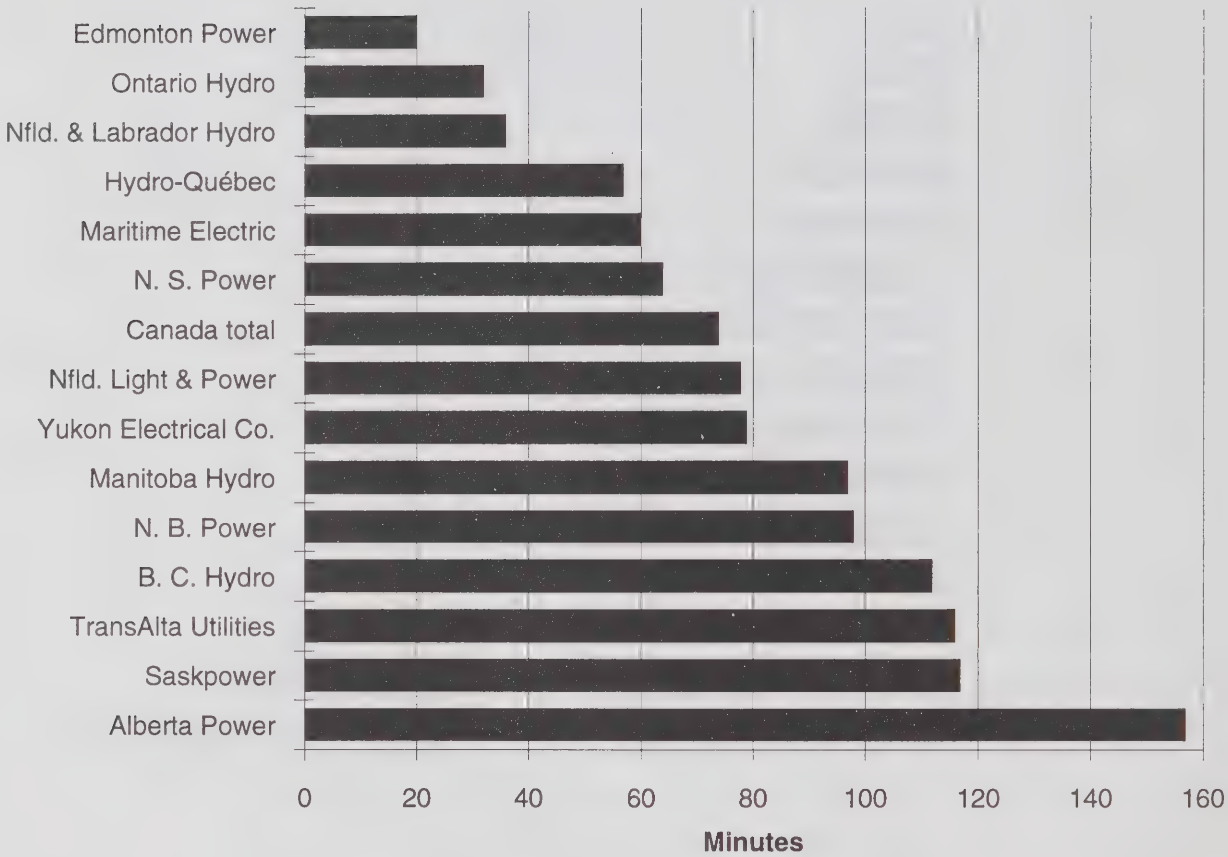
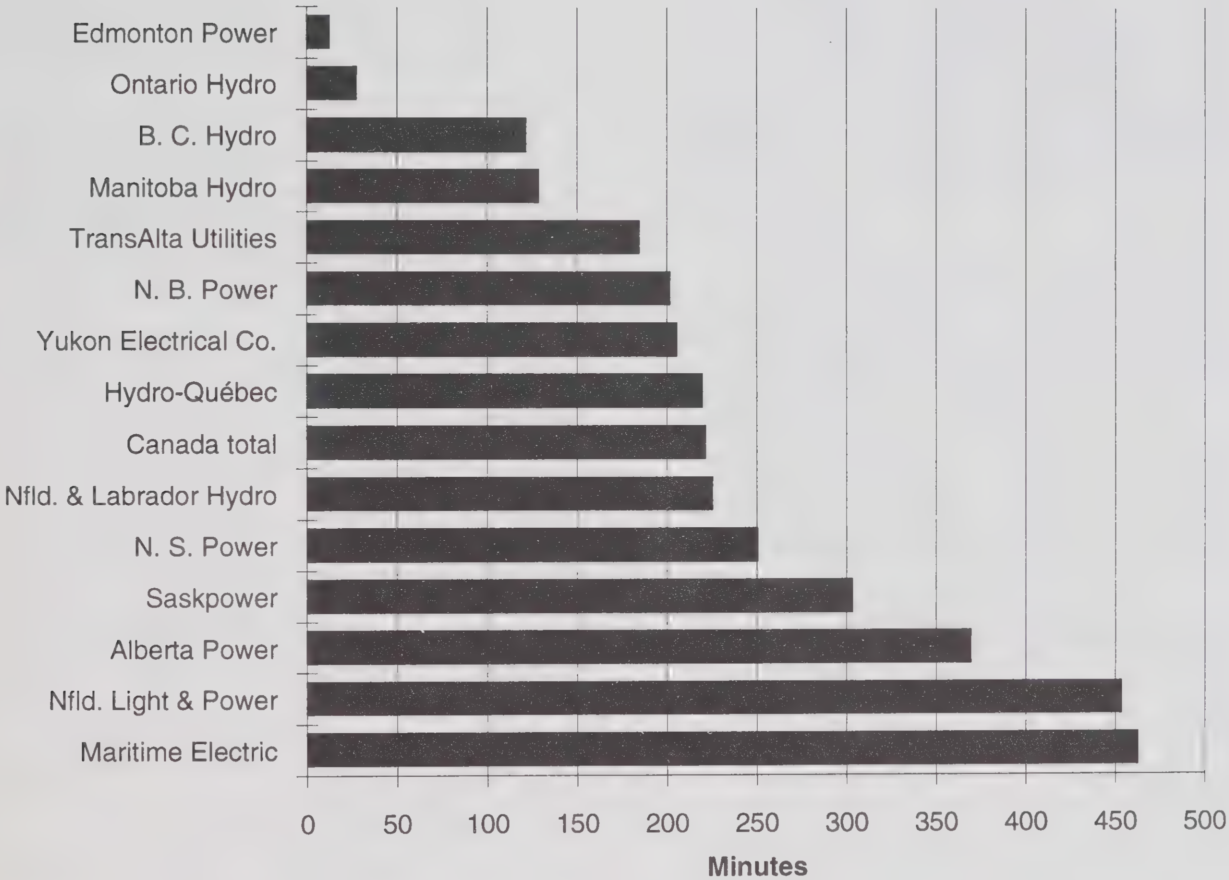


Figure 9.5 Average Interruption Time per Customer per Year



Electric Utility Investment and Financing

Capital Investment

The electric power industry is one of the most capital intensive industries in our economy. Between 1980 and 1991, the average capital-output ratio for the industry was 6.8. This means that in order to generate one dollar's worth of electricity, about seven dollars must be invested in the electric power industry. This capital-output ratio is very high, compared with 1.2 for total manufacturing industries, and 1.6 for the economy as a whole.

The most capital intensive type of electrical generation is nuclear. It is estimated that the capital cost of nuclear generation, including depreciation, the debt guarantee fee and financing charges, accounts for about 65 per cent of the total cost. The fuel cost accounts for only 14 per cent, and operation and maintenance for 21 per cent. Because of such a cost structure, nuclear energy is inflation proof over its 40-year life-service.

Every year, electric utilities invest in new facilities or upgrade old facilities to meet customer needs. From 1971 to 1992, electric utilities total capital investments increased from about $1.8 billion to $12.1 billion, with an average annual growth rate of 9.6 per cent. If the average annual inflation over this period (4.5%) is removed, the real annual growth rate is 5.1%. Table 10.1 illustrates the capital-intensive nature of electricity generation and its importance in the Canadian economy.

Since 1989, electric utility capital expenditures have been increased significantly, accounting for more than 53 per cent of the total capital investment in the energy sector. This increased investment is probably due to stronger-than-expected domestic demand.

Table 10.2 summarizes capital expenditures in the energy sector. During the period 1972-92, the electric power industry had the largest investment share in the energy sector, with the exceptions of 1984 and 1985, when petroleum and natural gas exploration and production had the largest share. Over the past 21 years, capital investment in the electric power industry totalled about $135 billion (accounting for 51 per cent of total investment in the energy sector).

In 1992, the electric power industry's investment share was 57 per cent of the total for the energy sector. This is a substantial increase from 1989, 1990 and 1991, indicating that the electric power industry may be returning to the high investment period of the 1970s (Table 10.1).

Of the total $135 billion capital investment between 1972 and 1992, about 56 per cent was invested in generation, 19 per cent in transmission, 13 per cent in distribution, and 12 per cent in others (Table 10.3). This represents a fairly large investment in generation for the period, since a traditional rule-of-thumb states that capital investment in generation normally accounts for 50 per cent of total investment in the industry. Figure 10.1 shows electric utility capital investment by function in 1992.

Table 10.4 reports the capital investment for 15 major electric utilities in 1991 and 1992. With the exceptions of Hydro-Québec and B.C. Hydro, all major utilities reduced their capital investment in 1992. Hydro-Québec was the largest money spender, accounting for 39 per cent of total utility capital investment in 1992, most of which was related to the on-going construction of the James Bay Phase II hydroelectric projects.

Capital Financing

To build a power project, an electric utility normally uses its reserve funds to finance a portion of the construction costs (self-financing),

with the larger portion of the costs usually financed by international and domestic debt borrowing (debt-financing) and bond and/or stock issues (equity-financing). Electric utilities regularly have to pay a fixed interest charge on debt- financing, while the payments on equity-financing, especially stock issues, are determined by the operation of the utility.

Canada's electric utilities rely heavily on foreign sources to finance their capital investment because of a relatively small financial market within the country. However, the degree of dependence on foreign financing has been reduced substantially since 1986. Some major electric utilities have tried to finance their power projects mainly from domestic financial markets in order to avoid foreign exchange losses. In 1985, foreign financial sources accounted for 52 per cent of the existing total long-term debt financing. This percentage was reduced to 46 in 1986, 43 in 1987, 40 in 1988, and 35 in 1990 and 1991. As of December 31, 1991, the total outstanding long-term debt of major electric utilities in Canada was about $83 billion. Of this total, about 65 per cent (or $54 billion) was borrowed on the domestic market, and 35 per cent (or $29 billion) on international markets. Of the $29 billion borrowed internationally, it is estimated that 86 per cent (or $25 billion) was raised in the United States; 5 per cent (or $1.6 billion) in Germany; 4 per cent (or $1.1 billion) in Switzerland; 3 per cent (or $993 million) in the United Kingdom; and 2 per cent (or $512 million) in Japan (Table 10.5).

In Canada and the United States, publicly owned electric utilities depend mainly on debt-financing. Investor-owned utilities, on the other hand, rely much more on equity-financing. Table 10.6 indicates that in 1991, Canadian publicly owned electric utilities had debt ratios ranging from 67 per cent to 97 per cent. With the exceptions of Nova Scotia Power (Nova Scotia Power was privatized in 1992) and Manitoba Hydro, all publicly owned utilities have strong financial positions. The debt ratios for investor-owned utilities ranged from 41 per cent to 44 per cent, indicating they are also financially sound.

High debt ratios, similar to those of Canadian publicly owned utilities, were also common among government-owned utilities in the United States. As Table 10.6 indicates, the Power Authority of the State of New York, the Tennessee Valley Authority, and the Bonneville Power Administration had debt ratios of 75, 84 and 100 per cent respectively. The selected American investor-owned utilities had debt ratios ranging from 39 per cent to 56 per cent in 1991. In general, the financial position of American investor-owned utilities is not as good as that of their Canadian counterparts.

Tables and figures referred to in this chapter are on the following pages.

Tables & Figures

Table 10.1
Electric Utility Capital Investment, 1971-1992

	Investment in electric power industry ($ million)	Utility investment as a percentage of total energy investment	Utility investment as a percentage of total investment in the economy	Utility investment as a percentage of GDP
1971	1 747	52	8	1.8
1972	1 754	49	7	1.6
1973	2 244	53	8	1.8
1974	2 753	53	8	1.8
1975	3 957	58	9	2.3
1976	4 229	55	9	2.1
1977	4 884	56	10	2.2
1978	5 936	58	11	2.5
1979	6 364	53	10	2.3
1980	6 109	42	8	2.0
1981	7 319	40	9	2.1
1982	8 408	39	10	2.2
1983	7 770	42	10	1.9
1984	6 340	37	8	1.4
1985	5 727	34	6	1.2
1986	5 618	41	6	1.1
1987	5 946	45	6	1.1
1988	6 971	44	7	1.2
1989	8 458	50	6	1.3
1990	10 291	52	8	1.5
1991	11 706	51	9	1.7
1992	12 045	57	10	1.8

Source: Natural Resources Canada

Table 10.2
Investment in Energy-Related Industries, 1972-1992

Year	Petroleum and Natural Gas: Exploration and Production	Refining and Marketing	Natural Gas Processing Plants & Distribution	Pipelines	Electric Power	Coal Mines & Products	Uranium Mines	Drilling Contractors	Total
	(millions of dollars)								
1972	666	351	272	447	1 754	42	11	24	3 567
1975	1 390	595	341	362	3 957	123	30	27	6 825
1980	5 745	502	698	602	6 109	306	277	198	14 437
1985	8 187	681	942	665	5 727	475	160	80	16 917
1986	5 401	723	782	587	5 618	434	144	30	13 724
1987	4 415	1 052	746	503	5 946	338	113	13	13 126
1988	5 590	1 135	875	829	6 971	345	139	17	15 901
1989	4 310	1 433	997	1 183	8 458	1	105	14	16 811
1990	4 751	1 382	1 112	1 817	10 291	8	138	12	19 841
1991	5 212	1 432	1 596	2 479	11 706	393	45	16	22 879
1992	4 010	951	1 328	2 424	12 045	230	101	10	21 099

Source: Natural Resources Canada

Table 10.3
Capital Investment by Function, 1972-1992

Year	Generation	Transmission	Distribution	Other	Total
	(millions of current dollars)				
1972	1 020	432	229	73	1 754
1975	2 460	616	547	334	3 957
1980	3 580	1 114	703	712	6 109
1985	2 941	836	1 008	942	5 727
1986	3 214	815	989	600	5 618
1987	2 774	1 200	1 039	933	5 946
1988	3 137	1 812	1 115	907	6 971
1989	4 313	2 115	1 269	761	8 458
1990	6 147	2 074	1 235	835	10 291
1991	6 276	2 525	1 384	1 521	11 706
1992	6 263	2 650	1 445	1 687	12 045

Source: Natural Resources Canada

Table 10.4
Capital Investment by Major Electric Utility

	1991	1992	Year-Over-Year Change
	(millions of current dollars)		
Newfoundland and Labrador Hydro	44	29	-15
Newfoundland Light & Power	47	46	-1
Maritime Electric Co. Ltd.	17	14	-3
Nova Scotia Power	374	172	-202
NB Power	600	518	-82
Hydro-Québec	4 074	4 127	53
Ontario Hydro	4 200	4 000	-200
Manitoba Hydro	487	356	-131
Saskatchewan Power	365	245	-120
Alberta Power	164	119	-45
Edmonton Power	250	110	-140
TransAlta Utilities	280	240	-40
B.C. Hydro	144	607	463
Yukon Energy Corporation	11	6	-5
Northwest Territories Power Corporation	19	9	-10
Canada	**11 076**	**10 598**	**-478**

Source: Natural Resources Canada

Table 10.5
Major Electric Utility Long-Term Debt and Sources of Financing, 1991

	Long-term Debt	Sources of Long-term Debt Financing	
	($ millions)	Domestic (%)	Foreign (%)
Newfoundland and Labrador Hydro	1 326	56	44
Newfoundland Light & Power	198	96	4
Maritime Electric Co. Ltd.	48	100	0
Nova Scotia Power	1 757	75	25
NB Power	2 342	61	39
Hydro-Québec	29 703	49	51
Ontario Hydro	32 160	79	21
Manitoba Hydro	4 092	40	60
Saskatchewan Power	1 115	52	48
Alberta Power	607	100	0
Edmonton Power	977	100	0
TransAlta Utilities	1 242	100	0
B.C. Hydro	6 886	40	60
Yukon Development Corporation	68	100	0
Northwest Territories Power Corp.	67	100	0
Canada	**82 586**	**65**	**35**

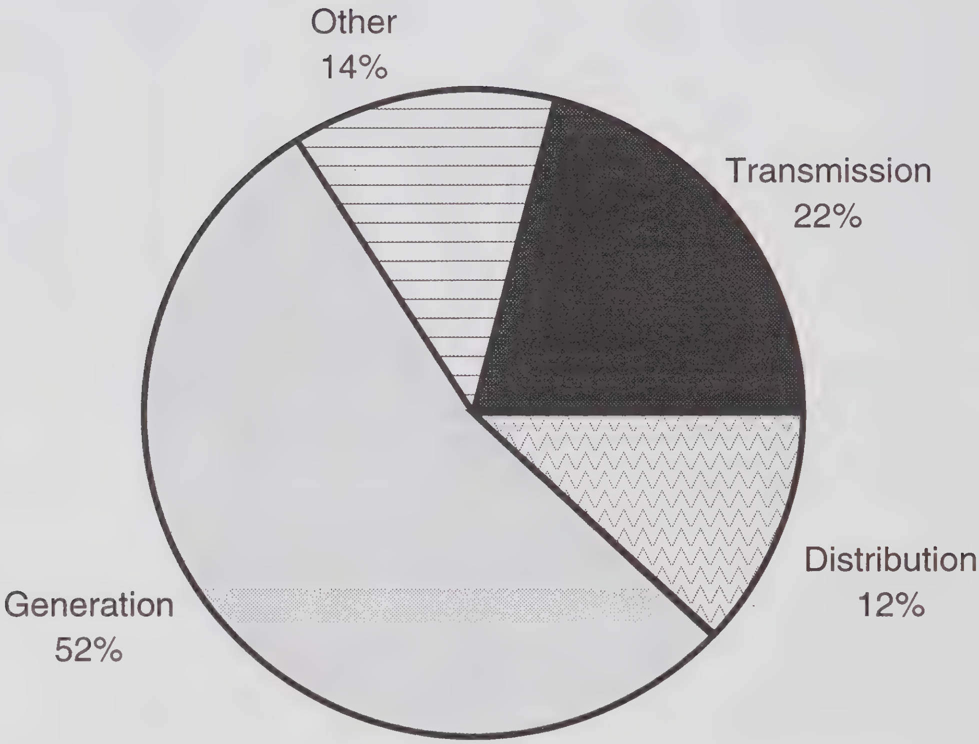
Source: Natural Resources Canada

Table 10.6
Comparison of Canadian and U.S. Electric Utility Debt Ratios, 1986-1991

	1986	1987	1988	1989	1990	1991
			(per cent)			
CANADA						
Publicly Owned Utilities						
Newfoundland and Labrador Hydro	88	86	83	82	84	74
Nova Scotia Power	96	98	99	97	96	95
NB Power	84	85	83	82	83	82
Hydro-Québec	76	75	74	74	75	67
Ontario Hydro	84	84	83	83	83	84
Manitoba Hydro	96	97	98	97	96	97
Winnipeg Hydro	71	72	75	69	75	70
Saskatchewan Power	88	87	81	74	69	67
Edmonton Power	75	75	75	76	73	73
B.C. Hydro	88	86	81	80	79	75
Investor-Owned Utilities						
Newfoundland Light & Power	43	48	44	48	43	41
Maritime Electric Co. Ltd.	42	43	47	47	39	44
TransAlta Utilities Corporation	38	35	39	41	45	40
Alberta Power	32	39	38	41	46	42
UNITED STATES						
Publicly Owned Utilities						
Tennessee Valley Authority	83	83	83	81	84	84
Bonneville Power Administration	100	100	100	100	100	100
Power Authority of the State of New York	72	74	69	68	70	75
Investor-Owned Utilities						
Boston Edison Company	46	48	50	52	55	54
Northeast Utilities	52	53	54	52	51	52
Consolidated Edison Company of New York	36	37	37	38	39	39
Niagara Mohawk Power Corporation	47	55	55	57	57	56
American Electric Power Company	53	54	52	47	50	50
Northern States Power Company	46	43	42	41	41	40
Washington Water Power Company	48	48	51	49	47	49
Pacific Gas and Electric Company	46	49	49	48	48	49

Source: Natural Resources Canada

Figure 10.1 Capital Investment by Function, 1992



Total Investment: $12.1 billion

Chapter 11

Costing and Pricing

Electricity Supply Costs

During the period 1962-1993, increases in the cost of building electric power stations, transmission lines, and distribution systems were relatively small.

The unit cost of supplying additional electricity increased rapidly during the period 1973-81 [which coincided with the first (1973) and second (1979) oil crises (see Table 11.1)]. There were two key reasons for the rapid increases in the cost of electricity: the high rate of inflation (as measured by the Consumer Price Index (CPI) or the Gross Domestic Product (GDP) deflator), with an average annual increase of 9.5 per cent; and the increased cost of fossil fuels, with an average annual increase of 15 per cent. In general, high levels of inflation affect the electric utility industry by increasing the cost of facility constructing and by increasing the cost of the funds required to finance the construction.

The average interest rate on long-term utility debt for the period 1962-92 is also shown in Table 11.1. Interest rates started to rise after the first oil crisis and reached a peak of 16.3 per cent in 1981. After this, they dropped steadily to about 11.9 per cent by 1990, 10.8 per cent by 1991, and 9.9 per cent by 1992.

Since 1982, construction cost increases have moderated significantly. Adjusted for inflation, recent increases in the supply cost of electricity have been very small or negative.

In 1991, the federal sales tax was removed from items where it had previously been deemed applicable. The Goods and Services Tax (GST) is not applied to any item within electric utilities construction costs; if utilities pay GST on their construction inputs, they are later reimbursed.

Table 11.2 summarizes the unit costs of the various fossil-fuels used for electricity generation. Like construction costs, unit fuel costs increased substantially during the period 1973-81. It is estimated that the cost of natural gas increased annually by an average of 30 per cent, petroleum by 23 per cent, eastern coal by 19 per cent, and western coal by 15 per cent.

Unit fossil-fuel costs reached a peak in 1985 but began to decline in 1986 with the collapse of world oil prices. In 1990, all unit costs of electricity generation increased, particularly those of petroleum and natural gas. A 13 per cent increase in the petroleum price was mainly due to the Persian Gulf War which started in August of that year. The price of natural gas increased by 15 per cent. Generally, electric utilities can bargain for a lower price if the demand for natural gas is high.

In 1991, the unit cost of using coal for electricity generation for the western provinces increased by 12 per cent, mainly attributed to a coal price increase of 11 per cent in Alberta. The price of natural gas used for electricity generation continued to increase by 2 per cent in 1991, indicating natural gas price may be in the trend of increasing because of recent strong demand.

The unit cost of electricity generated from coal varies between regions of the country depending upon the type of coal used, its source and the quantity required. The unit fuel cost of electricity generated from western Canadian coal increased from 1.11 mills per kWh in 1969 to 6.60 mills per kWh in 1991. In the same period, the cost of coal-fired generation in eastern Canada increased from 3.46 mills per kWh to 22.32 mills per kWh. This large cost-difference between the two regions is mainly due to the fact that coal used for electricity generation in western Canada is produced domestically, while a large proportion of the coal used in eastern Canada is imported.

Over the last 16 years, nuclear-generated electricity has had competitive unit fuel costs in Canada. In 1991, it cost 5.01 mills per kWh, compared with an average of 31.24 mills for petroleum, 22.20 mills for natural gas, 22.32 mills for eastern coal and 6.60 mills for western coal. However, in terms of percentage increases, the unit fuel cost of using uranium for electricity generation increased at an average annual rate of 10.4 per cent during the period 1976-91, compared with 5.5 per cent for western coal, 4.8 per cent for petroleum, 4.6 per cent for eastern coal and 4.3 per cent for natural gas.

Electricity Pricing

In Canada, electric utilities price electricity at the average cost of production, which is generally lower than the marginal cost of production. Although marginal-cost pricing of electricity has the advantage of achieving economic efficiency (i.e. closing the cost-price gap), this pricing method has not been adopted by the provinces and electric utilities because of the complexities of marginal costing and because average costing has provided low-cost electricity and enhanced opportunities for regional economic development.

Rate design has evolved since the first oil crisis of 1973, and several alternatives to marginal-cost pricing have been implemented. For example, declining block rates for residential users (i.e. the more you use the less you pay) have been replaced by a uniform rate in Newfoundland, Prince Edward Island, Saskatchewan, Alberta and the Yukon; seasonal time-of-use rates were introduced in Ontario in January 1989; and automatic adjustment clauses for the escalation of fuel costs have been built into the rate design of those utilities that operate baseload oil-fired stations. The objective of all of these rate design efforts is to close the cost-price gap. Rate methodologies will continue to evolve to meet the changing needs of customers.

Table 11.3 presents annual electricity rate increases for major electric utilities across Canada over the past 10 years. In 1992, Ontario Hydro had the highest rate increase with 11.8 per cent, followed by Edmonton Power, 8 per cent, B.C. Hydro and Alberta Power, 7 per cent. A weighted average for Canada was about 7.2 per cent, compared with 6.8 per cent in 1991. Increases were higher than the CPI, which registered increases of 5.6 per cent in 1991 and 1.5 per cent in 1992.

The average revenue from electricity sales for each province is provided in Table 11.4. Because electricity rates are regulated by provincial governments and are intended to cover a utility's costs, rate increases tend to parallel the rate of inflation. The average annual growth in unit revenue for Canada as a whole was 4.1 per cent during the period 1982-91. The national inflation rate, as measured by the CPI, was 4.7 per cent over the same period.

Figure 11.1 illustrates the movement of the electricity, oil and natural gas components of the CPI, as well as the CPI itself. It indicates that since the collapse of world oil prices in 1986, the electricity price component has increased in line with the CPI, while natural gas price indices have declined despite rising inflation. The oil price indices have also decreased since 1986, but have started to rise since 1990.

Income statements for the major electric utilities are summarized in Table 11.5. In 1992, 16 major electric utilities in Canada had total operating revenues of $22.6 billion and a net income of $2.0 billion. Hydro-Québec had the largest net income of $724 million, followed by Ontario Hydro with $312 million and B.C. Hydro with $220 million. Hydro-Québec's net income for 1991 was $760 million - $36 million higher than in 1992. High interest charged to

operations and more taxes paid to the Quebec government in 1992 were the main factors contributing to the relatively low net income for Hydro-Québec.

Electricity costs differ across the country primarily because of differences in generation mix, the size and location of the utility and its market, indigenous resources and geography. Table 11.6 gives typical monthly electricity bills for selected Canadian cities as of January 1993. Winnipeg had the lowest electricity costs in the residential and industrial sectors, and Fredericton in the commercial sector.

Tables and figures referred to in this chapter are on the following pages.

Tables & Figures

Table 11.1
Inflation, Interest Rates and Construction Costs, 1962-1992

	Average Interest Rate	Increase in Construction Costs					
		Hydro	Steam	Nuclear	Transmission	Distribution	CPI
				(per cent)			
1962	5.4	2.8	-	-	1.0	1.8	1.2
1963	5.5	3.3	-	-	1.5	0.4	1.7
1964	5.5	3.2	-	-	0.0	2.2	1.8
1965	5.7	5.0	-	-	5.7	2.2	2.5
1966	6.4	6.2	-	-	4.1	5.1	3.7
1967	6.7	3.6	1.1	-	5.2	1.6	3.5
1968	7.8	4.2	2.8	-	2.9	1.2	4.7
1969	8.6	5.7	6.8	-	4.4	4.3	4.5
1970	9.3	6.6	7.4	-	5.0	7.5	3.3
1971	8.5	4.6	6.0	-	5.5	3.5	2.9
1972	8.4	6.3	6.1	6.9	6.3	4.4	4.8
1973	8.6	9.2	9.2	9.5	8.8	9.4	7.6
1974	10.2	18.8	20.5	19.2	19.2	20.4	10.9
1975	10.7	14.3	13.4	13.1	17.6	12.3	10.8
1976	10.4	8.9	10.0	9.7	7.3	5.7	7.5
1977	9.6	5.9	7.9	7.5	7.8	6.6	8.0
1978	10.1	7.7	8.7	8.0	8.0	7.4	9.0
1979	10.9	8.7	11.0	12.7	14.8	13.5	9.2
1980	13.3	10.0	11.6	22.0	13.6	14.0	10.2
1981	16.3	13.7	11.9	11.4	11.3	9.1	12.5
1982	15.9	7.2	6.8	5.3	4.8	9.3	10.8
1983	12.7	4.6	4.1	5.0	3.8	4.1	5.8
1984	13.5	3.2	2.8	0.1	5.3	4.4	4.4
1985	11.7	1.7	3.8	4.8	0.9	5.2	4.0
1986	10.4	4.1	3.5	3.5	2.1	2.4	4.1
1987	10.7	4.1	3.0	1.9	3.8	3.1	4.4
1988	10.9	4.0	5.7	2.8	9.2	6.1	4.1
1989	10.8	3.4	4.2	5.1	3.6	3.8	5.0
1990	11.9	4.5	3.6	3.3	2.6	3.2	4.8
1991	10.8	2.3	2.2	1.8	-1.8	-0.9	5.6
1992	9.9	0.7	0.3	-	-1.3	0.8	1.5

Source: Interest Rates - McLeod Young Weir Limited's average corporate bonds yield. Construction costs and CPI-Statistics Canada publications 62-007 and 62-001

Table 11.2
Cost of Fuel for Electricity Generation, 1969-1991

	Eastern Coal*	Western Coal**	Petroleum	Natural Gas	Uranium	Total Fuels
			(mills/kWh)			
1969	3.46	1.11	4.97	2.54	-	3.24
1970	3.60	1.38	5.68	2.47	-	3.25
1971	4.20	1.28	5.98	3.15	-	3.46
1972	4.32	1.34	6.41	3.93	-	3.42
1973	4.65	1.43	7.06	3.74	-	3.13
1974	5.38	1.54	11.36	5.18	-	4.10
1975	8.64	2.07	12.87	7.17	-	6.16
1976	11.43	2.97	15.38	11.74	1.14	8.11
1977	11.89	3.20	19.01	15.21	1.34	8.40
1978	13.12	2.88	21.22	16.19	1.61	8.82
1979	16.50	3.11	23.93	15.22	1.65	9.62
1980	18.22	3.75	26.22	15.47	2.65	10.69
1981	20.48	4.83	40.77	23.22	2.68	12.22
1982	22.61	5.76	44.88	30.16	2.87	14.04
1983	23.71	5.96	57.27	31.17	3.25	13.20
1984	24.85	5.94	65.11	34.15	3.84	13.64
1985	26.07	6.59	68.02	31.81	4.74	13.54
1986	25.88	5.13	45.15	27.11	4.52	10.70
1987	25.07	5.84	37.22	22.20	4.77	11.63
1988	22.05	5.51	27.53	25.17	4.53	10.52
1989	20.96	5.63	29.08	18.78	4.62	11.16
1990	22.83	5.87	32.93	21.67	4.88	11.41
1991	22.32	6.60	31.24	22.20	5.01	10.90

* Nova Scotia, New Brunswick and Ontario.
** Alberta, Saskatchewan and Manitoba.

Source: Calculated from Electric Power Statistics, Statistics Canada, catalogue 57-202, various issues

Table 11.3
Average Annual Electricity Rate Increases, 1983-1992

	Rate Changes (%): Average of all Customer Classes									
	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
Nfld. & Labrador Hydro	18.2	-	-	-1.7	-	-	1.0	8.2	1.6	3.8
Nfld. Light & Power	12.0	-	-	8.7	3.0	-1.1	2.0	12.5	0.8	5.2
Maritime Electric Co.Ltd.	-**	-	3.7	-3.8	-	-1.3	-	5.5	5.3	2.6
Nova Scotia Power	-	-	-	-	-	-	6.3	2.5	5.0	2.1
NB Power	8.8	6.2	4.6	-	-	-	-	-	4.4	5.0
Hydro-Québec	7.3	4.0	4.0	5.4	4.9	3.9	4.7	7.4	7.0	3.5
Ontario Hydro	8.2	7.5	8.6	4.0	5.0	4.7	5.3	5.9	8.6	11.8
Manitoba Hydro	9.5	7.9	5.0	2.8	9.7	4.5	6.0	4.0	3.5	3.5
Saskatchewan Power	12.6	9.2	-	7.5	7.5	6.1	3.9	-1.9	-0.6	4.0
Edmonton Power	8.0	5.0	6.7	0	3.0	1.9	-	-	3.0	8.0
TransAlta Utilities	15.0	-	1.7	6.1	-1.8	-1.0	5.5	-1.1	12.0	3.0
Alberta Power	2	-	-4.3	-8.6	-5.0	14.5	2.6	3.7	17.0	7.0
B.C. Hydro	6.0	65	3.8	1.8	-	-	3.0	1.5	3.0	7.0
Yukon Energy	-	-	-	0.7	-	-	-	4.0	11.3	-2.3
NWT Electric	-	-	-	-	-	-	-	9.5	0	6.0
Weighted Canada	**-**	**-**	**6.2**	**4.1**	**4.2**	**3.5**	**4.3**	**4.9**	**6.8**	**7.2**

* Based on residential category.

** Does not reflect monthly changes to the cost of commodity and fuel adjustment charges.

Source: Natural Resources Canada

Table 11.4
Average Revenue from Electricity Sales by Province, 1982-1991

	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
	(current cents/kWh)									
Newfoundland	3.6	3.7	3.9	4.7	3.9	4.0	4.0	4.1	4.4	4.9
P.E.I.	12.0	12.3	12.8	12.9	11.5	10.3	10.8	10.2	10.8	11.3
Nova Scotia	5.9	6.9	7.5	7.3	6.9	6.8	7.0	6.9	7.2	7.4
New Brunswick	5.1	5.4	5.5	5.8	5.5	5.5	5.3	5.5	5.2	5.6
Quebec	3.1	3.4	3.4	3.5	3.4	3.4	3.6	3.9	4.3	4.6
Ontario	3.6	3.9	4.2	4.5	4.5	4.9	5.1	5.4	5.7	6.3
Manitoba	2.9	3.1	3.4	3.6	3.6	3.9	4.0	4.1	4.3	4.5
Saskatcewan	4.0	4.2	4.5	4.8	5.0	5.5	5.8	6.1	6.0	5.9
Alberta	4.9	5.2	5.4	5.4	5.4	5.3	5.0	4.9	5.2	5.2
British Columbia	3.8	3.8	4.1	4.4	4.2	4.2	4.2	4.2	4.3	4.7
Yukon	8.3	8.3	8.6	9.0	7.8	7.4	7.7	7.1	7.3	7.9
N.W.T.	14.8	17.9	16.7	16.3	15.9	17.6	17.7	20.7	19.9	21.0
Canada	**3.7**	**3.9**	**3.9**	**4.1**	**4.3**	**4.2**	**4.5**	**4.8**	**5.0**	**5.3**

Source: Statistics Canada publication 57-202

Table 11.5
Major Electric Utilities' Statements of Income, 1992

	Total Revenue	O&M	Fuel Costs	Power Pur-chased	Depre-ciation	Taxes	Interest	Ex-change Losses	Other Costs	Net Income
	(millions of current dollars)									
Nfld. & Labrador Hydro	369	109	44	-	38	-	147	-	6	25
Nfld. Light & Power	344	60	-	191	26	16	22	-	1	28
Maritime Elec. Co. Ltd.	81	32	-	22	6	5	5	-	3	8
Nova Scotia Power	508	118	172	5	58	10	139	-	(32)	38
NB Power	924	270	169	123	114	-	200	-	21	25
Hydro-Québec	6 807	1 935	-	304	796	594	2 390	64	-	724
Ontario Hydro	7 768	2 246	1 137	186	1 198	270	2 419	-	-	312
Manitoba Hydro	757	237	-	10	115	38	339	-	-	18
Winnipeg Hydro	117	36	-	54	3	-	11	-	-	13
Saskatchewan Power	720	216	138	-	115	-	144	-	-	107
Alberta Power	557	96	60	-	71	68	83	-	-	179
Edmonton Power	390	96	-	78	43	38	80	-	(4)	59
TransAlta Utilities	1 096	230	92	-	208	218	146	-	-	202
B.C. Hydro	2 072	373	317	-	256	108	617	-	181	220
Yukon Dev. Corp.	25	12	-	-	3	-	3	-	-	7
N.W.T. Power Corp.	93	40	33	-	9	-	9	-	(2)	4
Canada	**22 628**	**6 106**	**2 162**	**973**	**3 059**	**1 365**	**6 754**	**64**	**176**	**1 969**

Source: Obtained from electric utilities' annual reports, 1992

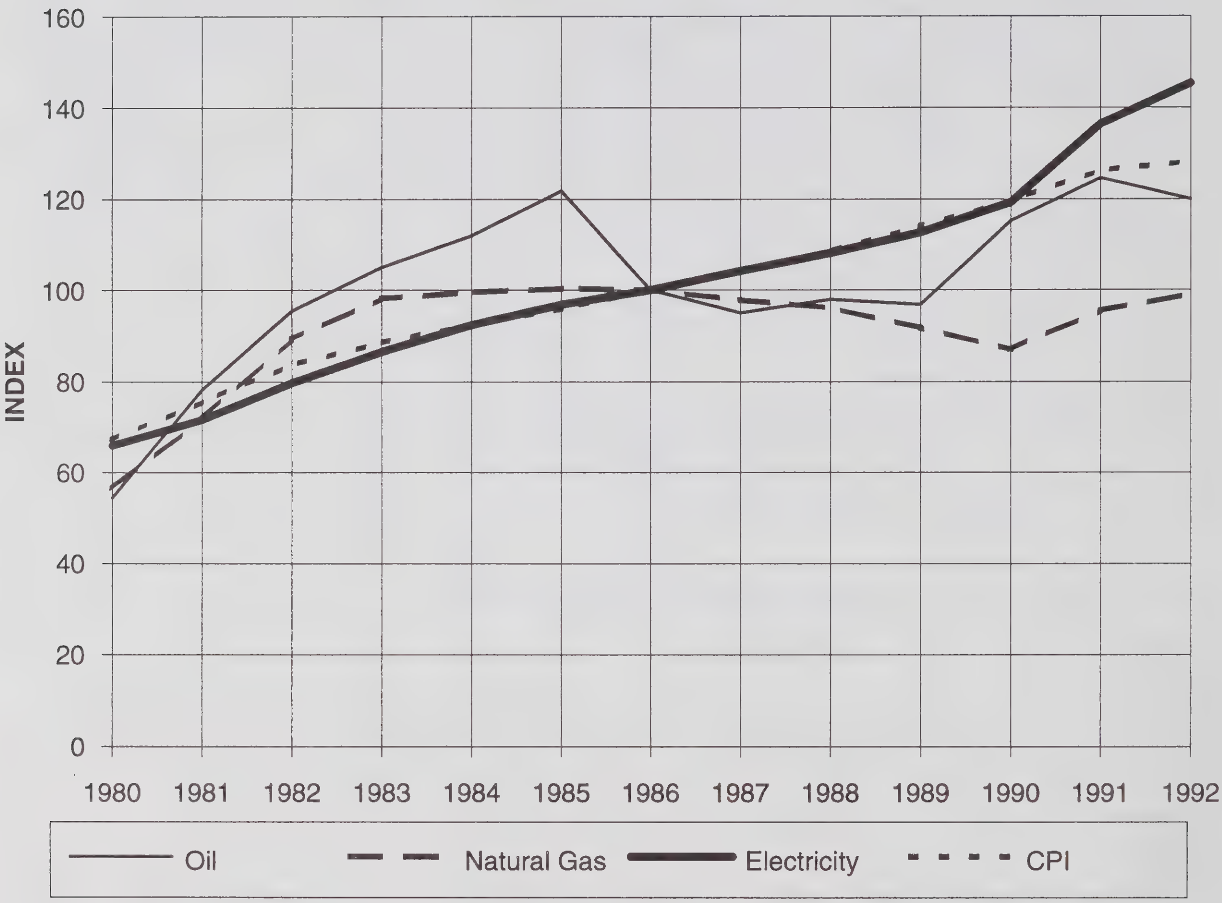
Table 11.6
Monthly Electricity Costs, January 1993 (Dollars)*

Sector:	Residential	Commercial	Industrial
Billing Demand (kW):	-	100	1000
Consumption (kWh):	1000	25 000	400 000
St. John's	86	2 424	24 273
Charlottetown	124	3 104	43 379
Halifax	93	2 544	26 982
Fredericton	72	1 737	22 420
Montreal	65	2 279	22 141
Ottawa	79	2 051	29 465
Toronto	101	2 826	34 500
Winnipeg	63	2 544	20 034
Regina	84	3 322	29 705
Saskatoon	98	2 670	31 999
Calgary	71	2 742	22 438
Edmonton	70	2 174	24 163
Vancouver	67	2 293	18 833
Whitehorse	86	2 661	
Yellowknife	141	3 546	

* Bills computed include sales tax, discounts and subsidies.

Source: Natural Resources Canada

Figure 11.1 Price Indices, 1980-1992



Electricity Outlook

Forecasts of electrical energy demand (kilowatt-hours) and peak load (kilowatts) are the starting points in the electric utility planning cycle. Forecasts of peak and energy demands are essential to ensure that sufficient generating capacity is available when it is needed. As the lead times required to add new generating capacity have lengthened, and the costs of new capacity have risen, the importance of forecasting has increased substantially.

The demand for electricity (both peak and energy) is affected by many variables. Some of them are easily identified while others are not; some can be measured, others cannot; in some cases their influence on the electricity load is rather straightforward, but in most cases the relationship is more subtle.

At the same time, forecasting electricity demand has become more difficult because of greater uncertainties about future input variables. Uncertainties associated with input variables, such as future electricity prices, fuel prices, economic growth, population, weather, efficiency standards, regulatory changes and other policy changes, create uncertainties in the forecasts of electricity demand. These uncertainties are in addition to the uncertainties inherent in the methodologies themselves used by electric utilities.

Forecasts of Electrical Energy Demand

As mentioned earlier, there are many factors affecting electrical energy demand. However, in the long-run, electricity demand will be mainly determined by economic and demographic activities. The economic activity is generally recognized as the most appropriate variable for explaining electricity demand. Slowdown or expansion of the economy plays a key role in determining electricity use. An increase or decrease of population will affect the formulation of households which, in turn, will also influence electricity use.

Economic and population growth in Canada over the next 18 years are expected to be significantly lower than the previous 32 years. It is estimated that the real Gross Domestic Product will grow at an average of only 2.5 per cent for the period 1992-2010, much less than the historical average of 3.9 per cent achieved during the period 1960-1992. Population is expected to grow at an average of 1.1 per cent for the period 1992-2010, less than the 1.3 per cent registered during the same period 1960-1992. In addition, it is expected that the country's economic structure will not shift greatly over the same period from predominantly service-producing industries to goods-producing industries. In general, goods-producing industries consume more electricity than those producing services. Demand-side management is expected to have greater emphasis in future electrical planning. Because of these expectations, electricity demand is projected to grow at a slower rate.

Table 12.1 summarizes electricity demand forecasts for the ten provinces and two territories. The projections of electrical energy demand within the service areas of the major electric utilities were prepared by the major utilities and provided to Natural Resources Canada in March 1993. Electricity demand for smaller utilities and industrial establishments was projected by the National Energy Board (NEB). The Electricity Branch of Natural Resources Canada (NRCan) combined these two sources of forecasts and produced a total electricity demand forecast for the provinces and territories. As Table 12.1 indicates, electricity demand for Canada as a whole is expected to grow at an average of 1.8 per cent during the period 1992-2010. This projected growth rate

was slightly greater than last year's forecast of 1.7 per cent for the same period.

Figure 12.1 compares various forecasts for total electricity demand in Canada. Included for comparison, are the latest forecasts derived from NRCan's Interfuel Substitution Demand Model, the NEB's Supply and Demand Model, and forecasts provided by the major electric utilities. On the basis of the control case, the NEB's projection of electricity demand for the next 18 years is 1.7 per cent annually, compared with the utilities' 1.8 per cent, and NRCan's 1.6 per cent. The difference among these three forecasts is mainly due to different underlying economic assumptions. All of these forecasts, however, are significantly lower than the average annual growth rate of 4.7 per cent achieved during the period 1960-92.

Forecasts of Peak Demand

The operation of an electrical system must meet two basic requirements: to generate enough energy to meet energy demand, and to have enough capacity to satisfy peak demand. All major electric utilities in the ten provinces and two territories have their peak loads in winter. Table 12.2 reports winter peaks projected mainly by the major electric utilities for the period 1992-2010. For Canada as a whole, peak demand is expected to grow at an average annual rate of 1.9 per cent, which is slightly greater than the 1.8 per cent projected for electrical energy demand. This suggests that the load factor for Canada's electrical system will decline slightly from 66 to 65 per cent during the period 1992-2010.

Forecasts of Generating Capacity

To meet the forecast growth in electricity demand shown in Tables 12.1 and 12.2, total installed generating capacity in Canada is expected to have a net addition of 18 297 MW during the period 1992-2010, with an average annual growth rate of 1.3 per cent (Table 12.3). This level of growth is slightly lower than those levels projected for energy and peak demand growth, reflecting the current surplus capacity situation in most of the provinces.

Table 12.4 presents installed generating capacity by fuel type for the period 1992-2010. Because of public concern about the environment, the capacity share of coal-fired generation is expected to decline significantly from about 18 per cent of the total capacity in 1992 to 13 per cent by the year 2010. On the contrary, the capacity share of hydro is expected to increase significantly at 57 per cent in 1992 to 62 per cent by 2010. Oil-fired and natural gas-fired stations are mainly reserved for peaking purposes. However, some natural gas-fired stations, such as co-generators, will be used for baseload generation and their respective capacity shares are expected to stabilize at 6 per cent and 5 per cent of the total over the same forecast period. The nuclear share is projected to decrease slightly from 13 per cent of the total in 1992 to 12 per cent by 2010 due to the moratorium of the nuclear program in Ontario. Other installed capacity is expected to increase slightly from 1 per cent in 1992 to about 2 per cent by 2010.

Figure 12.2 compares various forecasts of total generating capacity in Canada for the period 1992-2010. The electric utilities' forecasts are on the low side. Between 1992 and 2010, the electric utilities projected new capacity additions of only 19 GW, or about 1 056 MW per year. The NRCan projected capacity additions of 23 GW, or 1278 MW per year, and the NEB projected new additions of 25 GW, or 1389 MW

per year. In terms of the growth rate, the electric utilities' projection is 0.9 per cent annually, compared with 1.1 per cent for NRCan and 1.2 per cent for the NEB.

Forecasts of Electricity Generation

To meet both domestic electricity demand (Table 12.1) and export requirements (Table 12.7), the electric utilities have projected total electricity generation for the period 1992-2010 (Table 12.5). It is expected that hydro-based generation will continue to be the most important source of electric energy in Canada, with its share of total electricity production declining by 2 per cent, from 62 per cent in 1992 to 60 per cent in 2010. Coal-fired production is also expected to decrease its market share by 2 per cent, from 17 per cent in 1992 to 15 per cent by 2010, largely because of environmental concerns.

Even though falling world oil prices in recent years have provided electric utilities with an economic incentive to utilize their existing oil-fired stations in the short term, oil prices are not expected to remain low for long. In the long term, oil-fired stations will continue to be used mainly as peaking capacity and to meet energy demand in remote locations. Beyond 1992, the use of oil in electricity generation is expected to decline with the overall increase in demand. By the year 2010, the share of electricity generated from oil is expected to be 1.0 per cent of total electricity generation, compared with 3.0 per cent in 1992.

In the long term, the use of natural gas for electricity generation is expected to increase to around 8 per cent of the total generation. This is because a great majority of non-utility generation, such as co-generation, is expected to use natural gas as the input fuel.

The nuclear share of electricity generation is also expected to stabilize at 15 per cent during the period 1992-2010. New nuclear capacity will come from the Darlington station in Ontario, which will be completed in 1993. With no other nuclear stations under construction, it is anticipated that the nuclear share of electricity generation will decline after the year 2010.

It is worth noting that electric utilities, especially Ontario Hydro, TransAlta Utilities and B.C. Hydro, have projected a considerable amount of electricity to be derived from non-utility generation. Table 12.6 indicates that electricity generation from other sources, which includes non-utility generation, is expected to increase substantially starting in 1995. By the end of 2010, non-utility generation is expected to account for about 6 per cent of total electricity generation, compared with only 1.0 per cent in 1992. Of this 6 per cent non-utility generation share, it is estimated that about 5 per cent will use natural gas.

A comparison of various forecasts of electricity generation is presented in Figure 12.3. Between 1992 and 2010, the NEB projected that electricity generation will grow at average annual rate of 1.8 per cent. NRCan projected an annual growth rate of 1.7 per cent, and the electric utilities an annual growth rate of 1.5 per cent.

Forecasts of Electricity Exports to the United States

Canada and the United States enjoy essentially free trade in electricity: there is little direct government involvement in the contracting process, there are no tariffs, and there is no regulation over imports of electricity. With the Canada-United States Free Trade Agreement now in place, other non-trade barriers will be eliminated, gradually permitting an increase of electricity trade between the two countries.

Table 12.7 reports electric utilities' projected electricity exports to the United States for the period 1992-2010. B.C. Hydro's projections of electricity exports to the United States are always on the low side because interruptible sales are not incorporated into this forecast.

Forecasts of Fuel Requirements

Forecasts of fuel requirements for the period 1992-2010 are based on the forecasts of energy generation given in Table 12.6. Between 1992 and 2010, electricity generated from coal-fired stations is estimated to increase by 16 per cent, however, coal requirements are expected to increase only 12 per cent. This is because an increase of coal-fired generation is forecasted to take place particularly in New Brunswick, Nova Scotia, and Saskatchewan, where more efficient coal-fired plants are under construction or will be built. Alberta, which is traditionally a coal user province, is expected to reduce its coal-fired generation between 1992 and 2010, while Ontario will be increasing its coal-fired generation marginally during the same period.

The use of oil for electricity generation is estimated to decrease significantly from 1992 to 2010. As noted earlier, the use of oil will be restricted to meeting peak demand and providing electricity to remote communities.

However, the use of natural gas for electricity generation is projected to increase substantially between 1992 and 2010. Major industrial establishments, mainly in Alberta and Ontario, are the largest users. Electric utilities in Alberta and British Columbia also use a substantial amount of natural gas for electricity generation. Non-utility generators, such as co-generators, are expected to use natural gas as input fuel in the provinces of Ontario and Quebec.

With nuclear energy now an important component of Canada's electricity supply, the use of uranium for electricity generation is expected to increase at a rate of about 0.8 per cent per year during the period 1992-2010, because nuclear generation is expected to increase at the same rate through the improvement of the capacity factor.

Forecasts of Capital Expenditures

Over the next ten years 1993-2002, major electric utilities in Canada are expected to invest about $105 billion in facilities, an average of $11 billion per year. Quebec will be the largest investor, with $52 billion, accounting for 50 per cent of the total. A large share of this capital investment is expected to be spent on the James Bay Phase II and Grande Baleine hydro projects. Ontario is expected to invest about $32 billion in electrical energy, or about 31 per cent of Canada's total. Most of this expenditure will be for the completion of Darlington and some hydro projects (Table 12.9).

The electric utilities' capital investments by function are given in Tables 12.10 - 12.13. It is expected that generating facilities will account for 43 per cent of the total for the period 1993-2002, transmission and distribution 20 per cent each, and other facilities 17 per cent.

Forecasts of Emissions from Electricity Generation

Electric utilities project that carbon dioxide emissions will continue to decrease until 1994, from 99 million tonnes in 1992 to 89 million tonnes in 1994, due to the reduction of coal use for power generation. It is then estimated to increase gradually to 110 million tonnes by the year 2010. (Figure 12.4). Coal-fired generation is expected to account for 88 per cent of the

total, followed by 8 per cent for oil, and 4 per cent for natural gas.

Because of the application of new technologies to reduce emissions, electric utilities project that their sulphur dioxide emissions will be reduced significantly over the period 1992-2010 (Table 12.14). The projections of nitrous oxides emissions are shown in Table 12.15.

Tables and figures referred to in this chapter are on the following pages.

Tables & Figures

Table 12.1
Forecasts of Domestic Electrical Energy Demand (GWh)

	1992*	1993	1995	2000	2005	2010	Average Annual Growth Rate 1992-2010 (%)
Newfoundland	10 696	10 334	10 666	11 278	11 842	12 406	0.8
P.E.I.	772	777	812	920	1 059	1 222	2.6
Nova Scotia	9 908	9 984	10 477	11 322	12 331	13 621	1.8
New Brunswick	13 883	14 330	14 939	16 606	17 660	19 094	1.8
Quebec	164 605	180 176	191 276	208 276	219 676	228 976	1.9
Ontario	139 383	143 839	149 390	160 419	177 250	192 511	1.8
Manitoba	18 376	18 097	18 703	20 686	22 300	23 943	1.5
Saskatchewan	14 590	15 307	15 587	16 391	17 204	18 295	1.3
Alberta	45 906	45 953	48 251	52 346	55 919	59 692	1.5
British Columbia	57 270	61 610	65 110	70 610	76 210	83 210	2.1
Yukon	480	459	507	541	578	618	1.4
N.W.T.	581	623	634	635	639	641	0.5
Canada	**476 450**	**501 489**	**526 352**	**570 030**	**612 668**	**654 229**	**1.8**

Table 12.2
Forecasts of Domestic Peak Demand (MW)

	1992*	1993	1995	2000	2005	2010	Average Annual Growth Rate 1992-2010 (%)
Newfoundland	1 826	1 912	1 969	2 180	2 330	2 454	1.7
P.E.I.	138	138	144	159	181	206	2.3
Nova Scotia	1 821	1 914	1 962	2 102	2 233	2 440	1.6
New Brunswick	2 708	2 970	3 085	3 430	3 651	3 880	2.0
Quebec	30 449	32 834	34 681	37 639	41 666	43 586	2.0
Ontario	23 027	24 519	25 463	27 220	29 151	31 445	1.7
Manitoba	3 401	3 626	3 720	4 040	4 355	4 676	1.8
Saskatchewan	2 455	2 642	2 680	2 816	2 957	3 142	1.4
Alberta	6 758	7 105	7 387	7 921	8 422	8 822	1.5
British Columbia	10 064	10 431	53 031	11 661	12 721	14 151	1.9
Yukon	87	88	89	97	102	110	1.3
N.W.T.	102	120	122	120	123	125	1.1
Canada	**82 836**	**88 299**	**134 333**	**99 385**	**107 892**	**115 037**	**1.9**

* Actual data

Source: Canadian Electric Utilities and the National Energy Board

Table 12.3
Forecasts of Installed Generating Capacity by Province (MW)

	1992*	1993	1995	2000	2005	2010	Average Annual Growth Rate 1992-2010 (%)
Newfoundland	7 447	7 464	7 476	7 479	8 424	8 424	0.7
P.E.I.	122	124	124	148	148	148	1.1
Nova Scotia	2 330	2 347	2 347	2 347	2 512	2 677	0.8
New Brunswick	4 037	4 442	4 136	4 117	4 388	4 632	0.8
Quebec	31 104	32 354	34 246	36 528	40 715	43 053	1.8
Ontario	33 969	33 548	33 609	33 405	33 236	33 358	-0.1
Manitoba	5 312	5 227	5 227	5 227	6 193	6 088	0.8
Saskatchewan	3 144	3 060	3 062	3 062	3 062	3 434	0.5
Alberta	7 980	8 213	8 619	8 540	8 953	9 382	0.9
British Columbia	12 489	12 656	12 695	13 831	14 021	14 966	1.0
Yukon	135	133	141	146	149	155	0.8
N.W.T.	204	195	201	223	238	253	1.2
Canada	**108 273**	**109 763**	**111 883**	**115 053**	**122 039**	**126 570**	**0.9**

Table 12.4
Forecasts of Installed Generating Capacity by Fuel Type in Canada (MW)

	1992*	1993	1995	2000	2005	2010
Coal	19 464	18 692	18 901	18 642	17 894	16 956
Oil	7 961	7 960	7 864	6 796	7 257	7 964
Natural Gas	4 215	3 498	3 498	4 482	5 472	6 707
Nuclear	13 987	15 771	15 741	15 529	14 760	15 013
Hydro**	61 676	62 794	64 793	68 408	75 460	78 735
Other***	970	1 048	1 086	1 196	1 196	1 196
Total	**108 273**	**109 763**	**111 883**	**115 053**	**122 039**	**126 570**

* Actual data
** Includes 20 MW of tidal power
*** Generating capacity from woodchips and waste gases

Source: Canadian Electric Utilities and the National Energy Board

Table 12.5
Utility Forecasts of Electricity Generation by Province (GWh)

	1992*	1993	1995	2000	2005	2010	Average Annual Growth Rate 1992-2010 (%)
Newfoundland	36 681	36 497	37 009	37 681	38 290	38 983	0.3
P.E.I.	34	165	165	200	200	200	10.3
Nova Scotia	9 722	9 837	10 036	10 881	11 890	13120	1.7
New Brunswick	15 962	16 744	17 541	18 804	19 889	21 227	1.6
Quebec	147 077	153 876	164 576	180 776	194 676	204 376	1.8
Ontario	138 518	146 256	152 438	164 411	179 550	196 811	2.0
Manitoba	26 763	28 519	28 946	30 310	35 665	35 067	1.5
Saskatchewan	14 127	15 008	15 318	16 023	16 342	17 508	1.2
Alberta	47 520	47 501	49 621	50 064	48 634	49 761	0.3
British Columbia	64 058	62 330	65 510	72 260	76 720	83 080	1.5
Yukon	480	459	508	541	578	618	1.4
N.W.T.	581	623	634	635	639	641	0.5
Canada	**501 523**	**517 815**	**542 302**	**582 586**	**623 073**	**661 392**	**1.5**

Table 12.6
Forecasts of Electricity Generation by Fuel Type in Canada (GWh)

	1992*	1993	1995	2000	2005	2010
Coal	83 562	77 673	81 257	76 484	87 240	96 926
Oil	13 639	13 430	10 258	11 637	10 177	9 134
Natural Gas	10 888	11 745	10 936	10 386	14 943	22 077
Nuclear	76 022	87 922	94 613	101 937	99 959	102 342
Hydro**	312 134	318 399	330 380	356 504	383 375	394 902
Other***	5 278	8 646	14 858	25 638	27 379	36 011
Total	**501 523**	**517 815**	**542 302**	**623 073**	**623 073**	**661 392**

* Actual data

** Electrical generation from woodchips, waste gases, and non-utility generators.

Source: Canadian Electric Utilities and the National Energy Board.

Table 12.7
Electricity Exports to the United States (GWh)

	1992*	1993	1995	2000	2005	2010
New Brunswick	1 729	2 303	1 875	1 875	1 875	1 875
Quebec	8 826	9 800	9 400	12 900	14 700	14 700
Ontario	2 056	3 440	6 120	7 100	4 300	7 300
Manitoba	6 058	8 228	9 167	7 340	4 086	2 962
Saskatchewan	80	11	88	88	0	0
British Columbia	7 475	1 340	380	1 300	400	120
Canada	**26 224**	**25 122**	**27 030**	**30 603**	**25 361**	**26 957**

Table 12.8
Fuels Required for Electricity Generation in Canada

	Coal (10^3tonnes)	Oil (10^3m^3)	Natural Gas (10^6m^3)	Uranium (tonnes)
1992*	45 374	3 518	3 111	1 507
1993	43 138	3 308	3 319	1 641
1995	45 173	2 443	3 060	1 629
2000	43 486	2 875	2 906	1 741
2005	46 996	2 511	4 157	1 707
2010	50 986	2 276	5 961	1 748

* Actual data

Note: Average heat content for fuels used in electricity generation in Canada are as follows:

Coal (kj/kg): Bituminous = 29 579, Subbituminous = 18 373, Lignitie = 14 839, Total = 20 966.
Oil (kj/litre): Light = 38 403, Heating = 41 799, Diesel = 37 663, Total = 41 393.
Natural Gas (kj/m^3): 38 042
Uranium (kj/g): 690 687

Source: Canadian Electric Utilities and the National Energy Board

Table 12.9
Forecast of Capital Expenditures for Major Electric Utilities (Total)

	1992*	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
	(millions of current dollars)										
Nfld.	75	71	116	93	89	111	115	120	125	130	135
P.E.I.	14	13	40	36	20	12	13	13	13	13	13
N.S.	172	155	112	118	98	95	99	105	111	115	122
N.B.	518	308	219	117	132	152	357	161	168	107	107
Que.	4 127	4 417	4 272	4 247	4 738	5 174	5 502	5 447	6 002	6 333	6 018
Ont.	4 000	3 400	3 400	3 500	4 200	3 300	3 300	3 100	2 800	2 400	2 800
Man.	356	344	298	275	269	206	228	291	308	342	315
Sask.	245	294	265	250	218	192	189	174	187	138	140
Alta.	469	498	457	377	345	338	394	394	394	394	394
B.C.	607	607	702	733	754	1 076	732	712	712	712	712
Yukon	6	8	7	5	5	5	5	5	5	5	5
N.W.T.	9	16	11	8	2	2	2	2	2	2	2
Canada	**10 598**	**10 131**	**9 899**	**9 759**	**10 870**	**10 663**	**10 936**	**10 524**	**10 827**	**10 691**	**10 763**

Table 12.10
Forecast of Capital Expenditures for Major Electric Utilities (Generation)

	1992*	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
	(millions of current dollars)										
Nfld.	15	11	37	27	22	41	43	45	47	49	51
P.E.I.	6	6	29	25	9	1	1	1	1	1	1
N.S.	94	63	25	14	14	6	6	7	7	7	8
N.B.	424	242	149	46	61	78	281	84	89	26	26
Que.	1 899	2 005	1 670	1 842	2 291	2 780	2 929	2 825	3 132	3 191	2 769
Ont.	2 500	1 700	1 600	1 600	1 600	1 400	1 700	1 300	1 100	900	800
Man.	170	129	98	88	69	58	62	60	70	73	72
Sask.	102	119	78	43	26	37	15	11	28	3	2
Alta.	174	220	200	116	71	80	80	80	80	80	80
B.C.	116	129	171	182	202	452	144	226	226	226	226
Yukon	1	1	1	1	1	0	0	0	0	0	0
N.W.T.	8	15	10	7	1	1	1	1	1	1	1
Canada	**5 509**	**4 640**	**4 068**	**3 991**	**4 367**	**4 934**	**5 262**	**4 640**	**4 781**	**4 557**	**4 036**

*Actual data

Source: Canadian Electric Utilities and Department of Natural Resources Canada

Table 12.11
Forecast of Capital Expenditures for Major Electric Utilities (Transmission)

	1992*	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
	(millions of current dollars)										
Nfld.	14	12	10	7	8	16	17	18	19	20	21
P.E.I.	0	0	1	1	1	1	1	1	1	1	1
N.S.	30	22	15	31	11	16	17	18	19	20	21
N.B.	52	20	14	14	11	11	12	12	12	13	13
Que.	1 159	885	874	549	521	381	455	588	720	911	1 073
Ont.	700	800	800	900	1 100	900	600	700	700	600	900
Man.	96	109	91	74	81	13	52	112	111	141	111
Sask.	29	38	35	55	44	12	27	26	13	4	4
Alta.	96	72	65	73	82	55	111	111	111	111	111
B.C.	101	102	200	236	228	333	289	412	412	412	412
Yukon	0	0	0	0	0	0	0	0	0	0	0
N.W.T.	0	0	0	0	0	0	0	0	0	0	0
Canada	**2 277**	**2 060**	**2 105**	**1 940**	**2 087**	**1 738**	**1 581**	**1 998**	**2 118**	**2 233**	**2 667**

Table 12.12
Forecast of Capital Expenditures for Major Electric Utilities (Distribution)

	1992*	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
	(millions of current dollars)										
Nfld.	32	35	46	42	45	41	42	43	44	45	46
P.E.I.	6	4	6	7	7	7	8	8	8	8	8
N.S.	36	53	55	56	57	58	61	64	68	70	74
N.B.	37	41	49	50	53	55	56	57	59	60	60
Que.	527	897	1 004	1 097	1 106	1 185	1 240	1 112	1 217	1 289	1 211
Ont.	200	200	300	200	200	300	300	300	300	300	400
Man.	54	64	62	65	64	63	63	67	70	73	76
Sask.	99	119	132	133	131	126	129	120	128	113	115
Alta.	126	147	135	138	145	149	151	151	151	151	151
B.C.	157	195	210	203	209	216	223	58	58	58	58
Yukon	4	6	5	3	3	4	4	4	4	4	4
N.W.T.	1	1	1	1	1	1	1	1	1	1	1
Canada	**1 279**	**1 762**	**2 005**	**1 995**	**2 021**	**2 205**	**2 278**	**1 985**	**2 108**	**2 172**	**2 204**

*Actual data

Source: Canadian Electric Utilities and Department of Natural Resources Canada

Table 12.13
Forecast of Capital Expenditures for Major Electric Utilities (Other)

	1992*	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
					(millions of current dollars)						
Nfld.	14	13	23	17	14	13	13	14	15	16	17
P.E.I.	2	3	4	3	3	3	3	3	3	3	3
N.S.	12	17	17	17	16	15	15	16	17	18	19
N.B.	5	5	7	7	7	8	8	8	8	8	8
Que.	542	630	724	759	820	828	878	922	933	942	965
Ont.	600	700	700	800	1 300	700	700	800	700	600	700
Man.	36	42	47	48	55	72	51	52	57	55	56
Sask.	15	18	20	19	17	17	18	17	18	18	19
Alta.	73	59	57	50	47	54	52	52	52	52	52
B.C.	233	181	121	112	115	75	76	16	16	16	16
Yukon	1	1	1	1	1	1	1	1	1	1	1
N.W.T.	0	0	0	0	0	0	0	0	0	0	0
Canada	**1 533**	**1 669**	**1 721**	**1 833**	**2 395**	**1 786**	**1 815**	**1 901**	**1 820**	**1 729**	**1 856**

*Actual data

Source: Canadian Electric Utilities and Department of Natural Resources Canada

Table 12.14
Forecasts of SO_2 Emissions by Fuel Type in Canada

Year	Coal	Oil
1992	522	139
1993	475	138
1995	396	98
2000	409	116
2005	417	99
2010	445	76

Source: Canadian Electric Utilities

Table 12.15
Forecasts of NO_x Emissions by Fuel Type in Canada

Year	Coal	Oil	Natural Gas
1992	153	38	7
1993	142	37	7
1995	153	24	7
2000	139	29	6
2005	142	26	9
2010	150	22	8

Source: Canadian Electric Utilities

Figure 12.1 Comparison of Electrical Energy Demand Forecasts in Canada

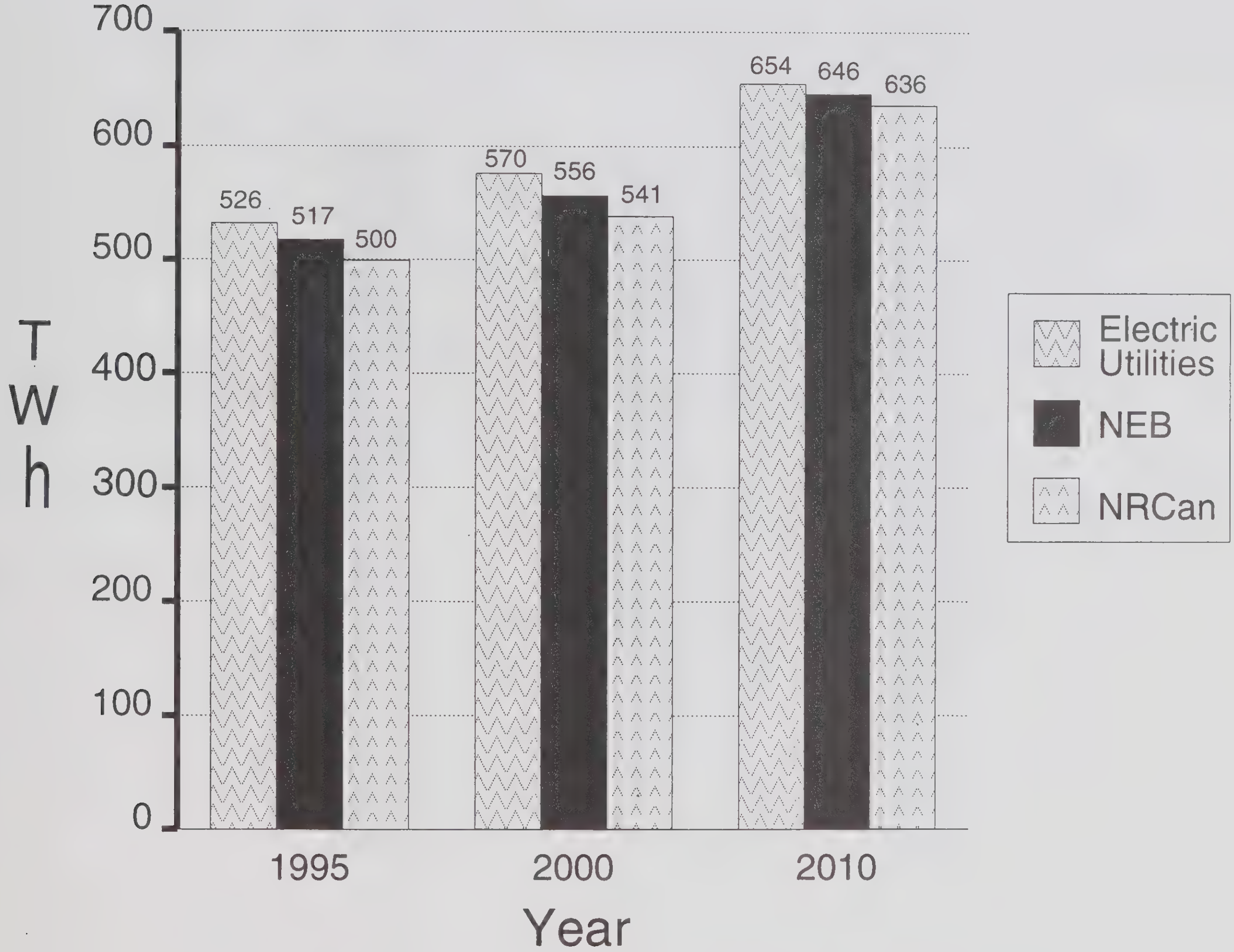


Figure 12.2 Comparison of Installed Generating Capacity Forecasts in Canada

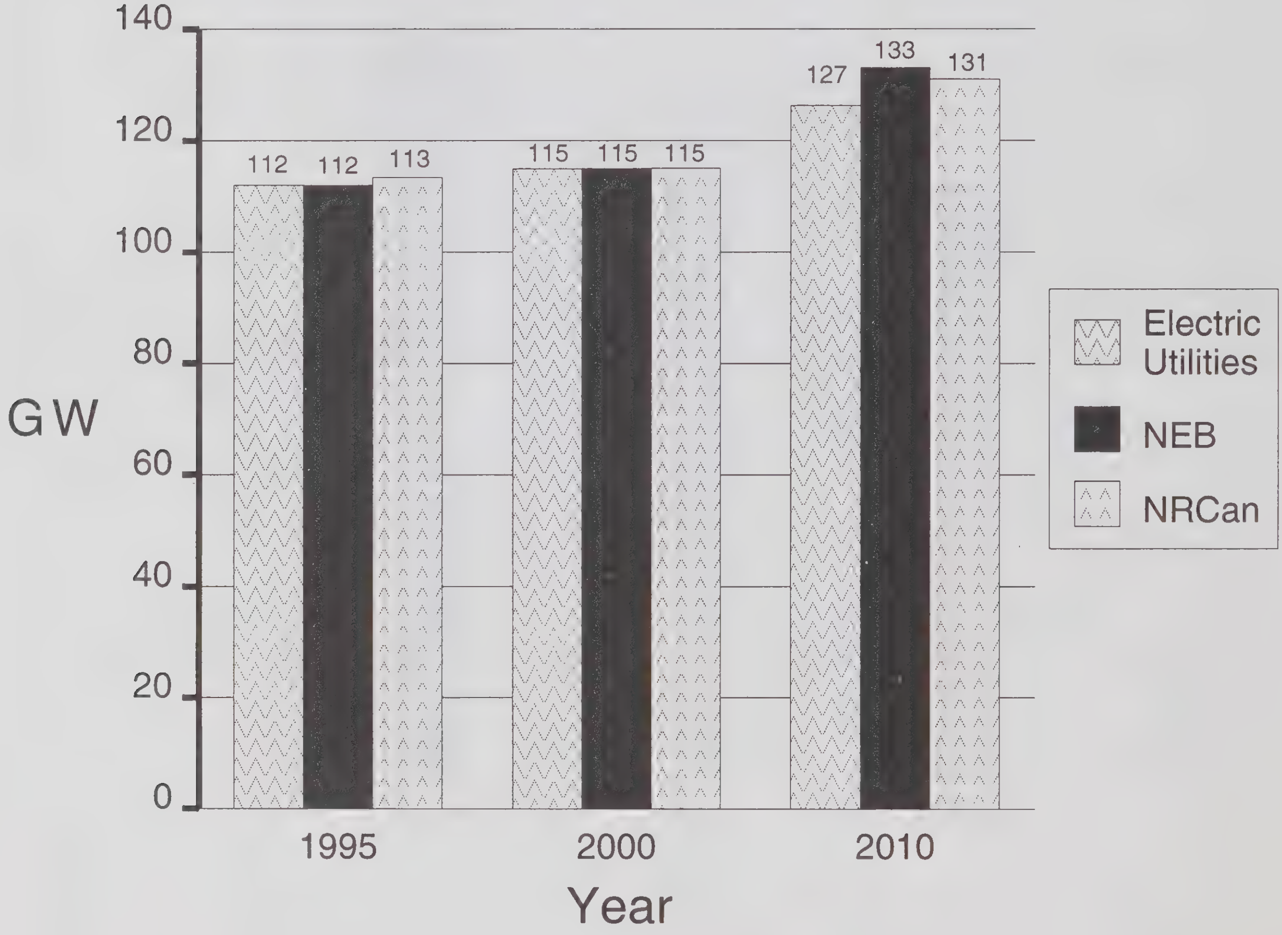


Figure 12.3 Comparison of Electricity Generation Forecasts in Canada

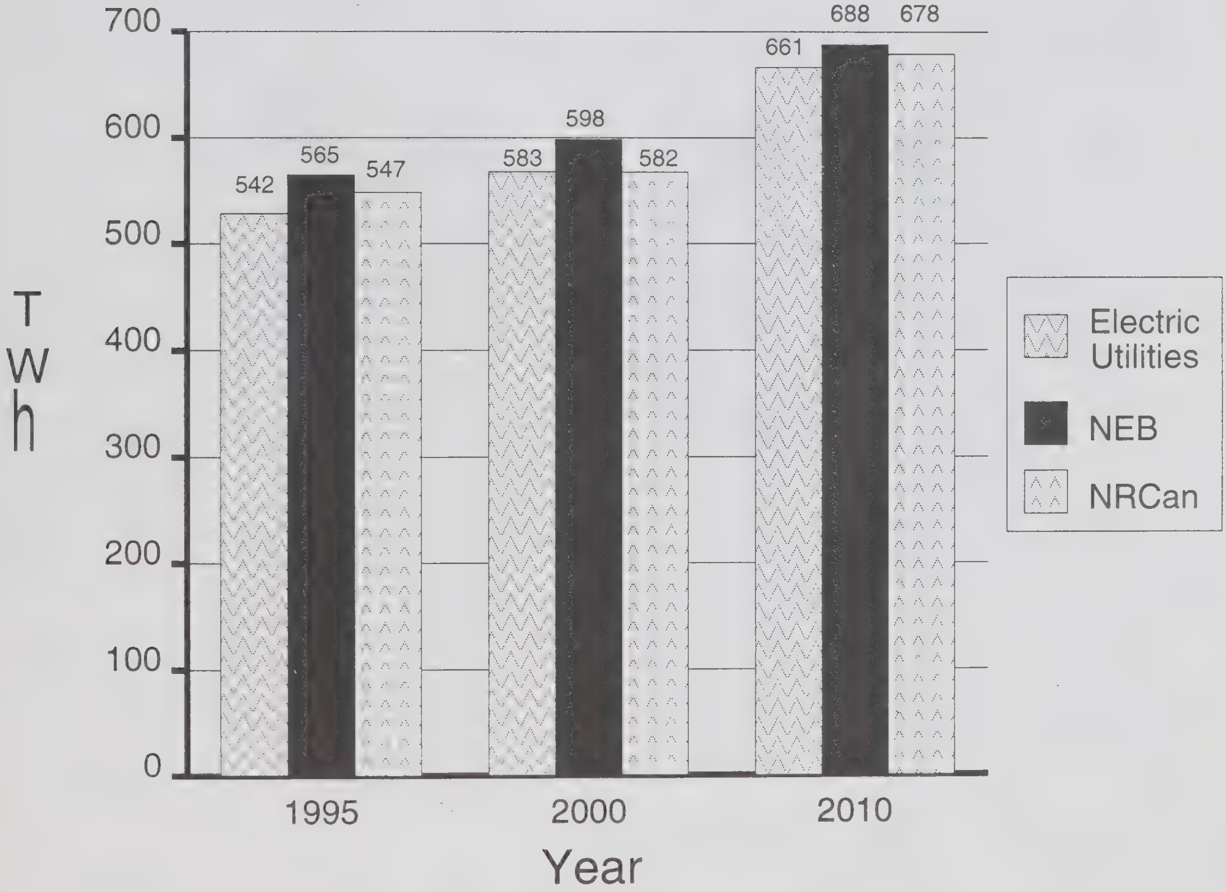
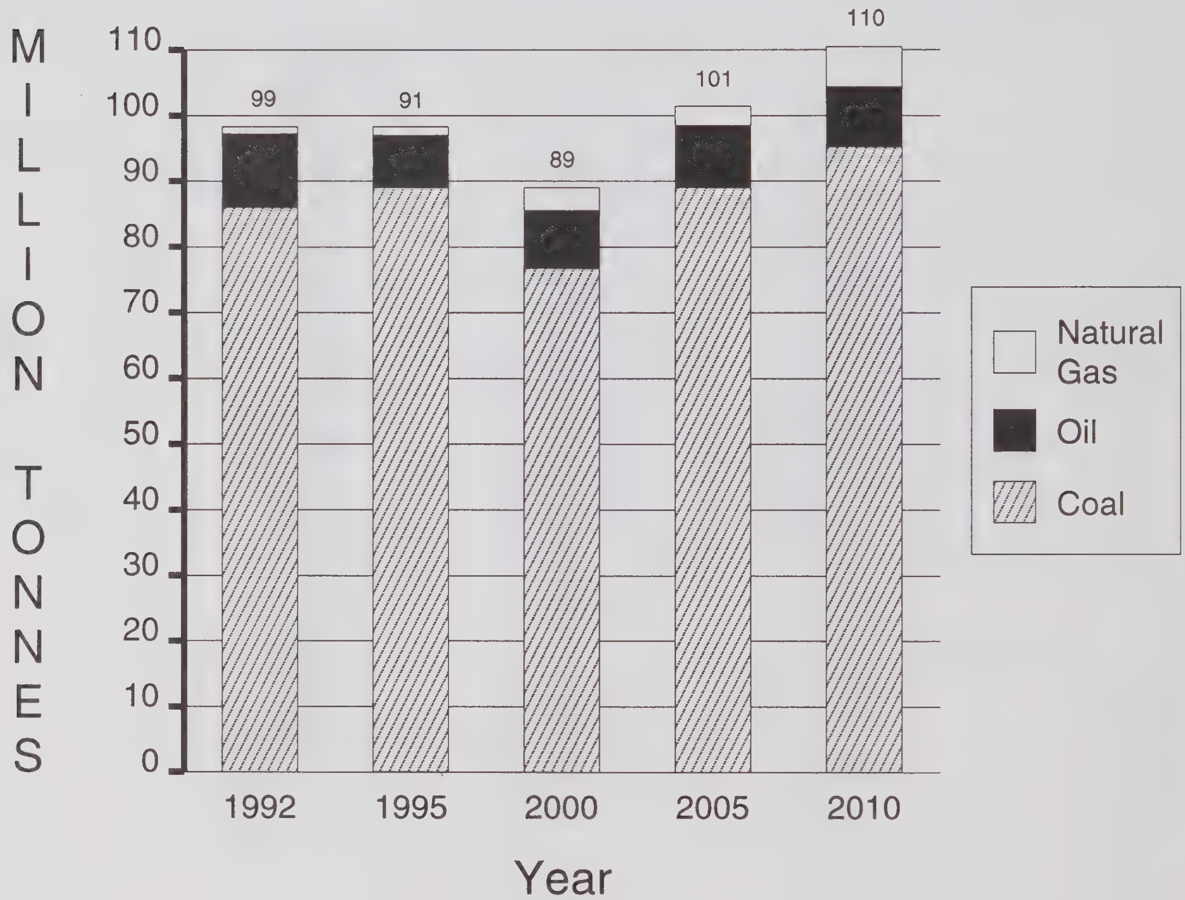


Figure 12.4 Forecasts of CO_2 Emissions by Fuel Type



Chapter 13

Demand-Side Management

Importance of Demand-Side Management

Demand-Side Management (DSM) is defined as the planning and implementation of electric utility activities that influence customer use of electricity in ways that will promote desirable changes in the utility's load shape.

Managing electrical demand is not a new concept for Canadian electric utilities. Utilities have been offering lower rates for interruptible service for many decades, and utility research into improving the efficiency of lighting dates back to the beginning of the century. Since entering the 1990s, however, the utilities have been increasing their efforts in demand-side management, and in some provinces individual initiatives are being integrated into comprehensive demand-management programs. Some of the programs include, Hydro-Québec's Energy Efficiency Project; Ontario Hydro's fuel substitution and efficiency standards; TransAlta Utilities' demand-oriented rates; and B.C. Hydro and SaskPower's *Power Smart*, which is designed to create an awareness of energy conservation. Canadian utilities see these programs as a means of providing quality electrical service in a flexible, economic and environmentally sensitive manner.

The traditional role of the electric utility has been to respond to increases in the demand for electrical energy by building new generating capacity. This approach has led to surplus capacity and a waste of resources when the increased demand did not materialize.

Operations designed to meet rather than manage load have cost implications for the utility and eventually the utility's customers. Under traditional utility planning practices, an increase in load results in a need to bring additional generating resources on-line. Over time, utilities are forced to develop more expensive generating resources, e.g. isolated hydroelectric projects, new or different fuel sources, and imports. New developments become increasingly more expensive and in some cases, are also associated with large environmental costs.

To serve this load growth, utilities have had to adapt their operations to customer-use patterns. To do this while keeping generation costs low, utilities have had to optimize the use of their supply. Two considerations are important in this optimization: (i) the fixed and variable costs of various forms of production, and (ii) the costs of changing electrical output levels over a short period of time. As a result of these cost considerations, the most economic means of serving load, generally, has been for utilities to maximize the use of generation with (i) low variable cost sources (hydro and nuclear facilities) to serve baseload requirements and (ii) higher variable cost sources (coal, gas and pumped storage) to serve intermediate- and peak-load requirements. Figure 13.1 illustrates the resources that a typical utility might use to meet its annual load.

As Canadian utilities evaluate the means of providing electrical service to meet future demand, increasingly they are faced with a difficult choice between rising costs of generation and the cost of DSM options.

Objectives of DSM

Utilities generally pursue DSM in order to (i) maximize efficiency in their existing operations (i.e. reduce the use of costlier

fuels and the period that generating plants sit idle); and (ii) minimize the requirement for new plants (i.e. reduce the need for peaking capacity, and delay the need for baseload capacity additions). The achievement of these goals brings a number of economic and environmental benefits, particularly low electricity rates and reduced environmental impacts.

There are five key objectives of DSM. They are:

Load Reduction -- reducing the amount of electricity required by customers. This can be achieved by improving electrical end-use efficiency.

Load Shifting -- reducing peak electricity demand by moving it to periods of lighter demand. An example of this type of initiative is time-of-use rates that reflect the higher cost of providing electricity during periods of peak demand.

Peak Clipping -- reducing peak electricity demand without shifting it to another period. This can be achieved by offering preferential rates to consumers willing to have load interrupted during peak periods.

Valley Filling -- promoting electricity use during off-peak hours to increase baseload generation and the efficiencies related to it. This can be achieved through reduced rates.

Load Building -- promoting electricity consumption during both the peak and the off-peak periods. Load building can be done through incentives to attract large electricity consumers.

These classifications and examples of typical programs designed to achieve DSM objectives are illustrated in Figure 13.2.

A utility decides which aspects of DSM it will implement based on its balance of demand and supply. Utilities that find themselves with significant excess supply because of a major loss of load, a recent large capacity addition, or lower than anticipated load growth, will tend to emphasize load-building programs. Conversely, as utilities approach a load/resource balance, they will likely emphasize load reduction or shifting efforts.

During the early and mid-1980s, many Canadian utilities had surplus generating capacity resulting from lower than anticipated demand. At that time, some utilities introduced programs to build load. These initiatives included advertising campaigns to increase consumption, preferential rates designed to attract energy-intensive industries, programs to promote fuel switching to electricity, and increased electricity export marketing efforts.

Today, the focus has changed. As average Canadian net surplus capacity has declined from 14 per cent in 1980 to 9 per cent in 1992 (see Table 7.7), utilities have cut programs to build load and begun to aggressively pursue load-reduction and load-shifting initiatives individually or in the context of a comprehensive DSM program. Generally these programs involve one or more alternative pricing policies, direct incentives, direct customer contact, and advertising.

DSM Initiatives

For ease of description, the types of initiatives utilities have embarked upon can be grouped into three classifications: energy efficiency improvements, load shifting, and interruptible load. Energy efficiency improvements are the main focus of electric utility DSM initiatives and programs.

Energy efficiency improvements include utility initiatives designed to increase the efficiency of electricity use among the utility's customers and thereby reduce load. These types of initiatives are generally intended to either improve the penetration of energy-efficient equipment in the marketplace or improve customers' operation of electrical equipment.

Load shifting refers to efforts by the utility to alter the timing of electrical demand among its customers. The goal of load shifting is to reduce peak demand that occurs in the daylight hours and, in Canada, during the winter. Demand is shifted to non-peak periods but total energy demand is not reduced.

Load shifting is more popular among utilities (i) where capacity is constrained, i.e., thermal as opposed to hydraulic systems, and (ii) where meeting the peak requires the operation of more expensive generating units or units with greater environmental impacts. Load shifting is generally done through rate design or direct control.

Interruptible load is the third type of DSM load reduction. It is also possibly the DSM initiative with which utilities have had the most experience. Interruptible load contracts are generally offered to large electricity consumers that have some form of back-up generation. Usually these are industrial or large institutional customers. In an interruptible load contract, the customer receives a preferential electricity rate in return for accepting the risk that electrical service will be curtailed intentionally by the utility in periods of high demand and tight supply.

Utility/Federal Cooperation

As outlined above, utilities implement a variety of programs in order to achieve their DSM objectives. Some of these programs are carried out in cooperation with Natural Resources Canada's (NRCan) Efficiency and Alternative Energy Branch. NRCan's *Partners in Integrated Resources Planning (PIRP)* Initiative deals with electrical and natural gas DSM, non-utility generation, co-generation and district heating and cooling.

PIRP will bring together various stake-holders in order to increase the adoption of DSM, non-utility generation, and other energy management techniques within the energy sector. It will act to coordinate and catalyze integrated planning and program efforts. Joint activities will involve energy supply stakeholder and manufacturers and suppliers of energy efficient and energy management equipment.

Utilities in the Maritime provinces, for example, contribute to NRCan's *Federal Buildings Initiatives (FBI)*, which is aimed at introducing energy efficiency programs for federal facilities. Another example of utility partnership with NRCan is in Saskatchewan, where SaskPower and NRCan are investigating opportunities to implement energy efficiency at Regina Airport.

A number of utilities have also entered into agreements with NRCan to cooperate on ventures related to NRCan's *R-2000 Efficient Home Program, Energy Innovators,* and industrial energy programs.

DSM and Canadian Electric Utilities

Prior to 1992, Canadian electric utilities saved 4275 MW of generating capacity resulting from the implementation of DSM programs, which accounted for 4 per cent of the total installed generating capacity. Hydro-Québec had the highest savings of 2870 MW, followed by Ontario Hydro with 683 MW, and SaskPower with 478 MW.

Table 13.1 summarizes Canadian utilities' forecasts of generating-capacity savings resulting from the implementation of DSM initiatives and programs for the years 1993, 2000 and 2010. The capacity savings are cumulative.

By the end of 1993, Canadian electrical utilities forecast DSM generating-capacity savings of about 6216 MW. The majority of the projected DSM savings will result from capacity interruptible load initiatives. This reflects mainly historic contracts with large consumers that are willing to accept occasional interruptions in service in exchange for reduced electrical rates. Most utilities offer such interruptible contracts. Hydro-Québec predicts 1580 MW of capacity interruptible load in 1993.

Load shifting will also contribute significantly to generating capacity savings, particularly as a result of Hydro-Québec's dual-energy program. Under this program, residential, commercial and industrial consumers use electricity for heating most of the time, but switch to another source of energy, such as heating oil, during peak heating periods (defined as when the temperature drops below a certain bench-mark). In exchange for switching off electricity during these peak periods, customers on this program receive a reduced rate for their off-peak consumption. Hydro-Québec projects a savings of 1500 MW in load shifting in 1993.

Only 15 per cent of 1992 Canadian utility capacity savings from DSM came from energy-efficiency improvements. However, this percentage is expected to increase to 20 per cent in 1993, reflecting the time lag of program development, implementation and penetration.

By the year 2000, the total DSM savings are expected to climb to 10 222 MW. At that time, about 43 per cent of the DSM savings will result from energy-efficiency improvements. These initiatives will be the basis of DSM programs for B.C. Hydro, SaskPower, Manitoba Hydro, Hydro-Québec, New Brunswick Power, and Maritime Electric. Utilities in Newfoundland, Nova Scotia, Ontario, and Alberta will continue to rely on capacity interruptible load for the bulk of their DSM savings. Electrical efficiency improvements will continue to be the major source of generating capacity savings to the year 2010. By that time, total savings are expected to climb to 13 776 MW. Of this total, 7212 MW (or 52 per cent) is attributed to electrical efficiency improvements.

Figure 13.3 illustrates the sectors from which the forecast savings will come. The information shows that, in 1993, 63 per cent of the savings will come from the industrial sector, reflecting the emphasis utilities have placed on load shifting and interruptible contracts with their large industrial customers. By 2000, the distribution of savings will be more balanced among the residential, commercial, and industrial sectors. This reflects the anticipated success of energy-efficiency improvements in the commercial sector, particularly improvements in lighting efficiency. Industrial savings are expected to account for 39 per cent of total peak-load savings by the year 2000.

Table 13.2 summarizes energy savings resulting from electrical efficiency

improvements. It is estimated that about 6146 GWh of electricity will be saved in 1993, compared with 1930 GWh in 1991, and 4151 GWh in 1992. The real impact of initiatives in this area will be significant by the year 2000, approaching 25 932 GWh. The energy-savings are expected to increase to over 43 000 GWh by 2010.

Projected Capital Costs of DSM

Most utilities are unable to estimate the costs of the DSM programs and initiatives that they are planning to undertake. Part of the reason relates to difficulties in determining the penetration rate of such programs. Another reason is that load reduction programs account for much of the DSM effort, and establishing the costs of these programs is complex and in many instances dependent upon the frequency of unanticipated shortages. Some of the smaller utilities identified that their DSM planning is not as detailed nor as long-term as other resource planning.

In 1992, all electric utilities in Canada with the exception of Newfoundland had invested a total of $541 million in DSM programs. Hydro-Québec was the largest spender with $257 million, followed by Ontario Hydro with $248 million, and Manitoba Hydro with $21.5 million. Only a few utilities have projected DSM expenditures to the year 2000: Hydro-Québec is intended to spend $270 million, followed by Nova Scotia Power with $44 million, and Manitoba Hydro with $37 million. Hydro-Québec also projects that it will spend about $415 million on DSM programs in the year 2010.

Tables and figures referred to in this chapter are on the following pages.

Tables & Figures

Table 13.1
Generating Capacity Savings from Electric Utilities' DSM Cumulative Values

	1992	1993				2000				2010			
	Actual	EEI*	LS*	CIL*	Total	EEI	LS	CIL	Total	EEI	LS	CIL	Total
						(MW)							
Nfld.	0	0	0	46	46	0	0	46	46	0	0	46	46
P.E.I.	21	4	0	19	23	13	0	20	33	13	0	20	33
N.S.	5	5	0	165	170	78	0	197	275	262	0	271	533
N.B.	9	19	0	80	99	141	0	80	221	266	0	80	346
Que.	2 870	250	1 500	1 580	3 330	1 960	1 750	1 200	4 910	4 080	1 430	1 200	6 710
Ont.	683	435	65	1 154	1 654	626	130	1 984	2 740	740	160	2 983	3 883
Man.	9	22	0	0	22	174	0	49	223	313	0	0	313
Sask.	478	320	20	150	490	387	20	153	560	445	20	153	618
Alta.	200	16	0	201	217	183	0	201	384	183	0	201	384
B.C.	75	165	0	0	165	830	0	0	830	910	0	0	910
Yukon	0	0	0	0	0	0	0	0	0	0	0	0	0
N.W.T.	0	0	0	0	0	0	0	0	0	0	0	0	0
Canada	**4 275**	**1 236**	**1 585**	**3 395**	**6 216**	**4 392**	**1 900**	**3 930**	**10 222**	**7 212**	**1 610**	**4 954**	**13 776**

* Note: EEI - Electrical Efficiency Improvements
LS - Load Shifting
CIL - Capacity Interruptible Load

Source: Obtained from a survey undertaken by the Electricity Branch, Natural Resources Canada, January 1992

Table 13.2
Energy Savings from Electrical Utilities' Efficiency Improvement Programs

	1992 Actual	1993	2000	2010
		(GWh)		
Nfld.	0	0	0	0
P.E.I.	3	9	34	34
N.S.	10	10	261	842
N.B.	37	72	576	1 180
Quebec	530	1 135	10 265	19 930
Ontario	2 055	3 140	8 040	12 912
Manitoba	30	80	816	1 414
Sask.	728	740	1 055	1 340
Alberta	33	70	910	910
B.C.	725	890	3 975	4 875
Canada	**4 151**	**6 146**	**25 932**	**43 437**

Source: Obtained from a survey undertaken by the Electricity Branch, Natural Resources Canada, January 1992.

Figure 13.1 Typical Annual Load Duration Curve and Generation Cost Minimization for an Electric Utility

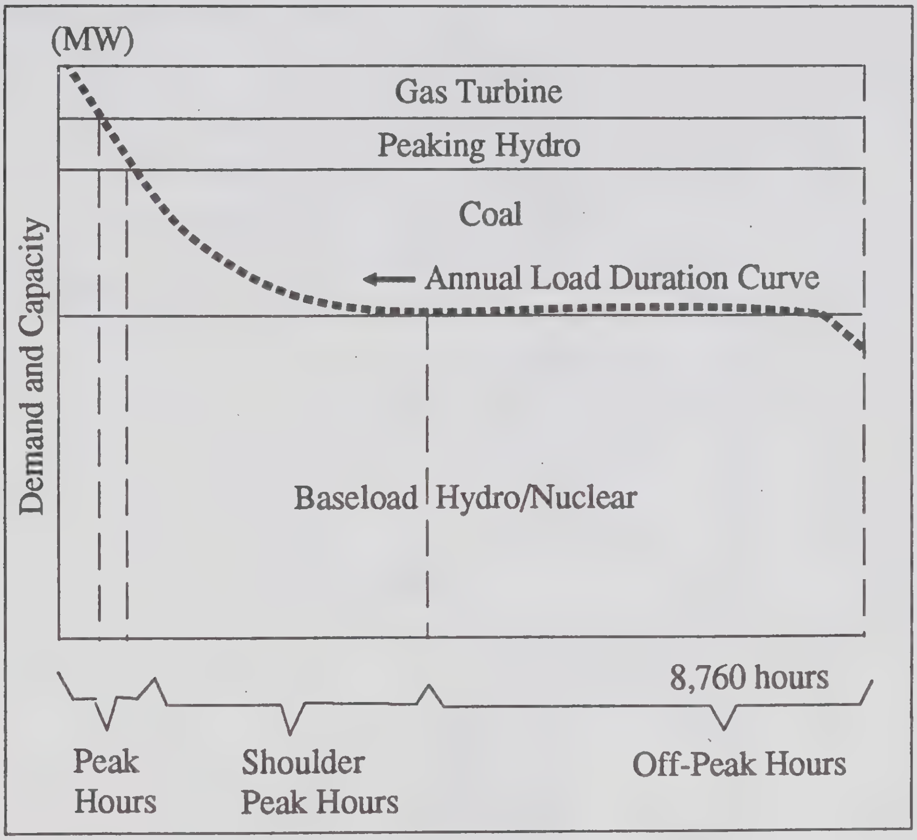
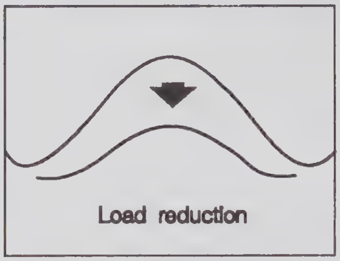
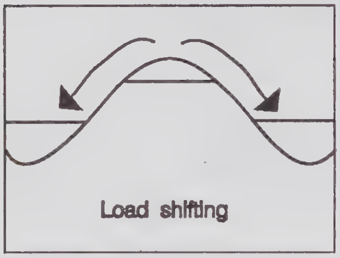


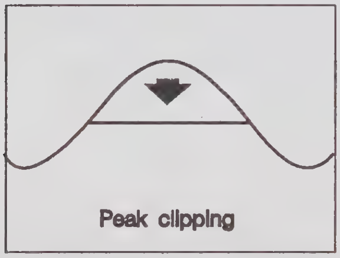
Figure 13.2 Demand-side Management Objectives and Programs



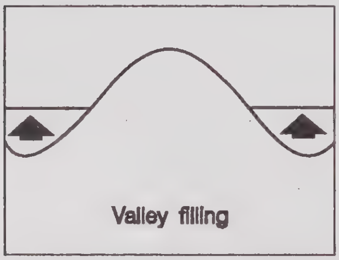
- improvements to end-use efficiency
- rate increases and restructuring



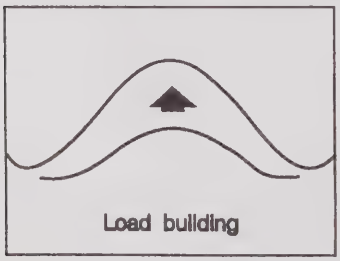
- time-of-use rates
- off-peak rates
- thermal energy storage
- direct load control



- time-of-use rates
- interruptible rates
- direct load control



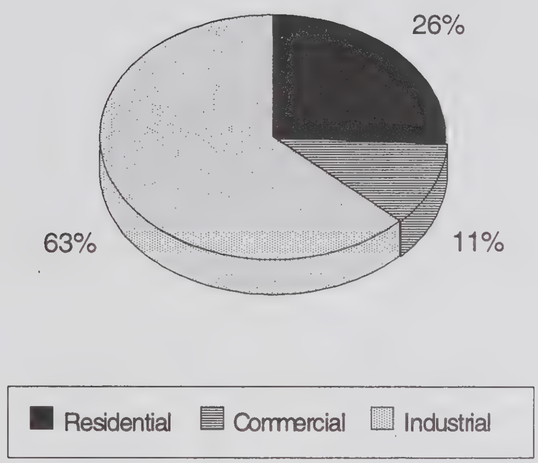
- time-of-use rates
- seasonal rates
- off-peak rates
- thermal energy storage



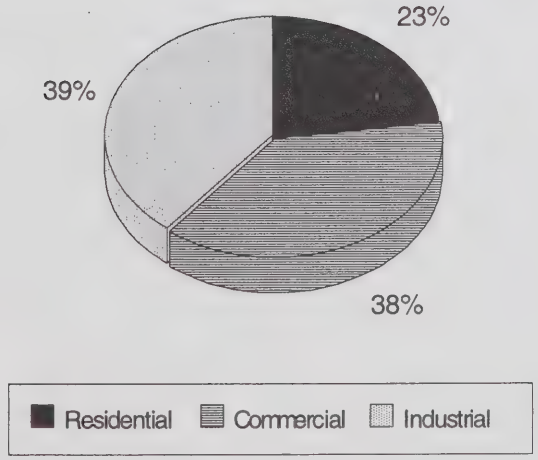
- promotional rates
- industrial electrotechnologies
- dual-fuel heating
- export marketing

Figure 13.3 Generating Capacity Savings by Sector due to DSM*

1993



2000



** Based on utility responses identifying capacity savings by sector, i.e. total savings in 1993 of 5 965 MW and in 2000 of 21 450 MW.*

Non-Utility Generation

Traditional suppliers of electricity in Canada include investor-owned, provincial, municipal and territorial electric utilities. Minor utilities and large industry have also contributed to the supply of electricity. Over the past several years, however, environmental concerns, rising electricity rates, and growing international competition have led to a re-examination of alternative sources of electricity such as self-generation and independent, or non-utility, generators.

Non-utility generation (NUG) is defined here as electricity generation from facilities owned and operated by companies other than the major electric utilities reported in Table 1.1. In this chapter, non-utility generation, independent power production, and parallel generation are used synonymously. This chapter examines the current contribution to electricity capacity and generation from NUG, the power purchase policies of the major utilities, and the future potential for NUG in Canada.

Current NUG Status

As of December 31, 1992, the total installed NUG capacity in service in Canada was estimated to be 7812 MW, or about 7.2 per cent of Canada's total generating capacity. Of this total, 6074 MW (78 per cent) was owned and operated by industrial establishments, mainly pulp and paper, mining, and aluminum smelting companies (Table 14.1). The remaining 1738 MW (22 per cent) was generated by private companies and minor public utilities (Table 14.2).

The largest share of installed NUG capacity is hydro, about 5670 MW or 73 per cent of the total. Waste fuels, including wood waste, flare gas, etc., contributed 970 MW or 12 per cent of total NUG generation; natural gas contributed 913 MW or 12 per cent; and oil contributed 259 MW or 3 per cent. NUG fuelled by natural gas, oil, wood waste, and flare gas was in the form of co-generation (i.e. generation producing electricity, and useable heat generally in the form of steam). This form of NUG capacity totalled 2142 MW in 1992. About 42 per cent of total NUG capacity is located in Quebec, 26 per cent in British Columbia, 16 per cent in Ontario, and 9 per cent in Alberta.

It is estimated that a total of 47 372 GWh of electricity was generated by NUG facilities in 1992, accounting for 9.5 per cent of total Canadian electricity generation. Of this total, 39 808 GWh (84 per cent) was self-generation by large industry, and the remainder was generated by minor utilities and independent generators. (Tables 14.3 and 14.4). Of the total 47 372 GWh of non-utility generation, about 37 773 GWh (80 per cent) was hydroelectric, followed by natural gas with 5125 GWh (11 per cent), other generation with 3637 GWh (7 per cent), and oil with 837 GWh (2 per cent).

Power Purchase Policies

Electricity supplied by a non-utility generator may be sold to a major electric utility or used to meet the producer's own electricity needs, i.e. self-generation. Although non-utility generators produced 47 372 GWh of electricity in 1992, it is estimated that only 1800 GWh (3.9 per cent) of this was sold to the major utilities. Ontario Hydro purchased about 1565 GWh, followed by Hydro-Québec (112 GWh), Alberta Integrated System (74 GWh), and New Brunswick Power (55 GWh). The remaining 1992 NUG was for independent use.

All major electric utilities have established policies concerning the purchase of electricity from NUG projects. Most utilities purchase electricity from non-utility generators at rates that reflect their long-term value to the power

system. Appendix C summarizes power purchase rates of the major utilities across Canada for non-utility generation.

The following briefly outlines some NUG policies and developments in selected provinces.

Ontario Hydro has established the following policy elements for NUG:

- to remain committed to NUG as an essential part of future energy supply;

- to purchase electricity from non-utility generators at rates that reflect the costs Ontario Hydro would incur to generate the power;

- to purchase electricity from non-utility generators with power ratings of 5 MW or less through standard pre-approved rate schedules; and

- to purchase electricity from non-utility generators with power ratings greater than 5 MW through negotiation or by requests for proposals.

In Alberta, the provincial government passed the *Small Power Research and Development Act* (the Act) on May 11, 1988. The purpose of the Act is to facilitate the generation of electricity in Alberta through small projects using wind, hydro, and biomass resources, and to monitor production from small power projects. The results of the monitoring will allow Alberta to determine the contribution that small power projects can make to the province's electricity supply in the long term.

Under the Act, the purchase price for NUG projects is fixed at 5.2 cents per kWh until 1994, and the amount of power purchased at this price will be limited to 125 MW. The purchase contracts will be limited to between 15 and 25 years.

On October 15, 1992, the government of British Columbia announced its policy on the role of independent power producers (IPPs) in meeting domestic electricity needs. Acquisition of electricity from IPPs will be driven by domestic needs, and resources will be acquired according to their social costs. IPPs will not be invited to bid on hydro sites in basins already developed by B.C. Hydro, or on large hydro sites (in excess of 100 MW) in undeveloped basins that B.C. Hydro could efficiently develop. With respect to small power opportunities (under 5 MW), B.C. Hydro and the provincial government will identify areas where independent power developments would be appropriate and issue specific requests for proposals.

In British Columbia, all electricity generating resources acquisition will be evaluated on a social cost basis, and the final prices determined through competitive process. Social costs and benefits will be incorporated through an evaluation framework that includes recognition of the potential of NUG projects to reduce environmental problems and provide employment opportunities in areas of high regional unemployment. In addition, POWEREX will assist the development of IPPs for export by providing technical and market expertise to the private sector. POWEREX will also facilitate arrangements for IPP's to deliver power to the export market.

Although Hydro-Québec has purchased electricity produced by industry for some time, Hydromega Development was the first independent power producer in Quebec to develop and operate small hydro generating stations expressly for the purpose of selling the output to Hydro-Québec. Hydromega owns and operates two hydro generating stations with installed capacities of 2.4 MW and 2.0 MW. Hydro-Québec purchases Hydromega's output at rates based on marginal costs. The term of the contract is 20 years.

In Saskatchewan, there are no NUG projects operating under contract to SaskPower. The province has 43 MW of installed cogeneration capacity ranging from 26 MW at the Weyerhaeuser pulp mill near Prince Albert, to a small unit at the North Battleford Hospital. These are self-generation projects which do not produce electricity for sale to SaskPower. However, SaskPower has indicated that proposals are being requested for 25 MW of NUG capacity for start-up in 1995. This request will allow SaskPower to gain experience with NUG.

As indicated in Appendix C, the power purchase rates of the major utilities are generally based on avoided-cost principles. As a result, the price of purchases of non-utility generation should generally be equal to or less than the cost of future generation by the major utilities.

NUG Potential in Canada

This section presents the forecasts of the major electric utilities for non-utility generation expected to come into service over the planning period 1993-2010. The utilities have prepared the forecasts based in part on the economics of non-utility generation from the perspective of the NUG developer, and have taken into account the developers' equipment costs, fuel costs, and return on investment, as well as the projected purchase rates offered by the utilities..

Table 14.5 summarizes forecast NUG capacity for the period 1993-2010. According to the utilities' estimates, a total of 3794 MW of NUG capacity is attainable by the year 2000. Of this total, co-generation, fuelled mainly by natural gas, will account for 62 per cent, followed by other thermal (waste fuels) with 24 per cent, and small hydro with 14 per cent. By 2000, it is projected that the majority of new non-utility generators will be located in Ontario (63 per cent), Quebec (20 per cent), and British Columbia (10 per cent). By 2010, it is estimated that total attainable NUG capacity will increase to 3836 MW. Co-generation fuelled by natural gas will continue to supply the largest share of total NUG in 2010 with 62 per cent, followed by other thermal with 25 per cent, and small hydro with 13 per cent. It is also forecast that Ontario will continue to have the largest share of NUG with 62 per cent of total non-utility generation in 2010. The growth in NUG reported above is substantially less than that forecasted by major utilities last year in which non-utility generation was expected to reach 9684 MW by the year 2010. The reduction stems primarily from reduced projections of growth in electricity demand and the consequent reduction in the need for new generating capacity.

The future development of NUG will depend on the profitability of NUG projects and the need for additional generating capacity. Achieving an acceptable rate of return on investment is a critical factor for non-utility generators. According to Ontario Hydro's estimates, rates of return on investment in the range of 15 to 20 per cent are required by a developer before a NUG project will be undertaken. The rate of return is linked to the purchase rate offered by the major utilities. With regard to the need for additional capacity, most of the major utilities will not require additional generating capacity for some years and thus may defer purchases from non-utility generators in the near term.

At present, the amount of electricity generated in Canada from independent power producers is relatively small. However, in the past few years, electricity planners have begun to give NUG a much greater emphasis, especially where such generation is produced from renewable or waste resources, or at higher efficiencies than conventional generators. It is expected that NUG will play an increasingly important role in the development of Canada's electricity service in the next decade or two.

Tables are on the following pages.

Tables & Figures

Table 14.1
Industrial Installed Generating Capacity by Fuel Type, 1992

	Conventional Thermal							
	Coal	Oil	Gas	Sub-Total	Nuclear	Hydro	Other	Total
				(MW)				
Nfld.	0	11	0	11	0	78	0	89
P.E.I.	0	0	0	0	0	0	0	0
N.S.	0	29	0	29	0	5	19	53
N.B.	0	71	0	71	0	18	87	176
Quebec	0	23	8	31	0	2 572	5	2 608
Ontario	0	0	437	437	0	243	91	771
Manitoba	0	3	4	7	0	0	23	30
Sask.	0	22	36	58	0	0	22	80
Alberta	0	0	357	357	0	0	65	422
B.C.	0	97	51	148	0	1 305	367	1 820
Yukon	0	0	0	0	0	0	0	0
N.W.T.	0	2	20	22	0	3	0	25
Canada	**0**	**258**	**913**	**1 171**	**0**	**4 224**	**679**	**6 074**

Source: Electric Power Statistics, Volume III, Statistics Canada, catalogue 57-206 and Electricity Branch, Natural Resources Canada

Table 14.2
Minor Utility Installed Generating Capacity by Fuel Type, 1992

	Conventional Thermal							
	Coal	Oil	Gas	Sub-Total	Nuclear	Hydro	Other	Total
				(MW)				
Nfld.	0	0	0	0	0	129	5	134
P.E.I.	0	0	0	0	0	0	0	0
N.S.	0	0	0	0	0	0	0	0
N.B.	0	1	0	1	0	34	0	35
Quebec	0	0	0	0	0	638	0	638
Ontario	0	0	0	0	0	434	15	449
Manitoba	0	0	0	0	0	0	0	0
Sask.	0	0	0	0	0	0	0	0
Alberta	0	0	0	0	0	0	271	271
B.C.	0	0	0	0	0	211	0	211
Yukon	0	0	0	0	0	0	0	0
N.W.T.	0	0	0	0	0	0	0	0
Canada	**0**	**1**	**0**	**1**	**0**	**1 446**	**291**	**1 738**

Source: Electric Power Branch, National Energy Board, March 1993 and Electricity Branch, Natural Resources Canada, March 1993

Table 14.3
Industrial Energy Generation by Fuel Type, 1992

	Conventional Thermal							
	Coal	Oil	Gas	Sub-Total	Nuclear	Hydro	Other	Total
				(GWh)				
Nfld.	0	0	0	0	0	499	0	499
P.E.I.	0	0	0	0	0	0	0	0
N.S.	0	187	0	187	0	39	156	382
N.B.	0	325	0	325	0	71	273	669
Quebec	0	0	0	0	0	17 488	0	17 488
Ontario	0	0	2 338	2 338	0	1 444	190	3 972
Manitoba	0	3	7	10	0	0	50	60
Sask.	0	38	193	231	0	0	178	409
Alberta	0	0	2 355	2 355	0	0	1 296	3 651
B.C.	0	283	420	420	0	10 643	1 494	12 557
Yukon	0	0	0	0	0	0	0	0
N.W.T.	0	0	95	95	0	26	0	121
Canada	**0**	**836**	**5 125**	**5 961**	**0**	**30 210**	**3 637**	**39 808**

Source: Electric Power Statistics, Volume III, Statistics Canada, catalogue 57-206 and Electricity Branch, Natural Resources Canada

Table 14.4
Minor Utility Energy Generation Capacity by Fuel Type, 1992

	Conventional Thermal							
	Coal	Oil	Gas	Sub-Total	Nuclear	Hydro	Other	Total
				(GWh)				
Nfld.	0	0	0	0	0	880	0	880
P.E.I.	0	0	0	0	0	0	0	0
N.S.	0	0	0	0	0	0	0	0
N.B.	0	0	0	0	0	0	0	0
Quebec	0	0	0	0	0	3 727	0	3 727
Ontario	0	1	0	1	0	1 829	0	1 830
Manitoba	0	0	0	0	0	0	0	0
Sask.	0	0	0	0	0	0	0	0
Alberta	0	0	0	0	0	0	0	0
B.C.	0	0	0	0	0	1 127	0	1 127
Yukon	0	0	0	0	0	0	0	0
N.W.T.	0	0	0	0	0	0	0	0
Canada	**0**	**1**	**0**	**1**	**0**	**7 563**	**0**	**7 564**

Source: Electric Power Branch, National Energy Board, March 1993, and Electricity Branch, Natural Resources Canada, March 1993

Table 14.5
Projections of Attainable Non-Utility Generating Capacity

	1993	2000			2010		
		Hydraulic	Cogeneration	Other Thermal	Hydraulic	Cogeneration	Other Thermal
	(MW)						
Nfld.	0	50	0	6	50	0	6
N.S.	9	5	30	23	5	30	19
N.B.	10	9	0	52	9	0	52
Quebec	52	72	579	109	72	550	109
Ontario	702	259	1 463	664	257	1 463	664
Sask.	60	0	85	18	0	135	43
Alberta	0	0	0	0	0	0	0
B.C.	186	105	210	55	105*	210	55
Canada	**1 019**	**500**	**2 367**	**927**	**500**	**2 388**	**948**

* May be developed by B.C. Hydro or NUG.

Source: Canadian electric utilities, March 1993

Table 14.6
Projections of Attainable Non-Utility Generation

	1993	2000			2010		
		Hydraulic	Cogeneration	Other Thermal	Hydraulic	Cogeneration	Other Thermal
	(GWh)						
Nfld.	0	263	0	0	263	0	0
N.B.	55	47	0	108	47	0	108
N.S.	73	26	243	172	26	240	140
Quebec	361	510	4 494	820	510	4 210	820
Ontario	3 975	1 130	10 280	4 961	1 130	10 280	4 961
Sask.	420	0	600	106	0	950	280
B.C.	487	394	1 609	399	260	1 609	399
Canada	**5 371**	**2 370**	**17 226**	**6 566**	**2 236**	**17 289**	**6 708**

Source: Canadian electric utilities, March 1993

Table A1.
Installed Capacity and Electrical Energy Consumption in Canada, 1920-1992

	INSTALLED CAPACITY										
	Thermal										
Year	Conventional	Nuclear	Sub-total	Hydro	Total	Electrical Energy Consumption	Average Demand	Peak Demand	Reserve Margin		Load Factor
	(MW)					(GWh) (a)	(MW) (b)	(MW) (c)	(MW) (d)	(%)	(%) (e)
1920	300	-	300	1 700	2 000	-	-	-	-	-	-
1930	400	-	400	4 300	4 700	19 468	2 222	-	-	-	-
1940	500	-	500	6 200	6 700	33 062	3 774	-	-	-	-
1950	900	-	900	8 900	9 800	55 037	6 283	-	-	-	-
1955	2 100	-	2 100	12 600	14 700	81 000	9 247	12 536	2 164	17	74
1960	4 392	-	4 392	18 643	23 035	109 304	12 478	17 264	5 771	33	72
1965	7 557	20	7 577	21 771	29 348	144 165	16 457	24 167	5 181	21	68
1970	14 287	240	14 527	28 298	42 826	202 337	23 098	34 592	8 234	24	67
1975	21 404	2 666	24 070	37 282	61 352	265 955	30 360	46 187	15 165	33	66
1976	23 039	3 466	26 505	39 488	65 993	284 829	32 515	49 527	16 456	33	66
1977	24 699	5 066	29 765	40 810	70 575	299 673	34 209	52 001	18 574	36	66
1978	26 154	5 866	32 020	41 898	73 918	316 435	36 123	54 106	19 812	37	67
1979	27 353	5 866	33 219	44 009	77 228	323 465	36 925	55 699	21 529	39	66
1980	28 363	5 866	34 229	47 770	81 999	340 068	38 821	59 167	22 832	39	66
1981	28 493	5 600	34 093	49 216	83 308	346 333	39 536	59 237	24 071	41	67
1982	28 957	6 547	35 504	50 007	85 511	345 115	39 397	62 417	23 094	37	63
1983	30 447	7 771	38 218	51 274	89 492	359 838	41 077	66 866	22 626	34	61
1984	30 427	9 813	40 240	54 949	95 189	385 516	44 009	65 798	29 391	45	67
1985	30 475	10 664	41 139	55 880	97 019	406 859	46 445	71 235	25 784	36	65
1986	30 979	11 364	42 343	57 731	100 074	423 027	48 153	70 364	29 710	42	68
1987	30 800	12 528	43 328	57 945	101 273	439 710	50 195	77 923	23 350	30	64
1988	30 525	12 593	43 118	57 937	101 055	462 948	52 848	78 961	22 094	28	67
1989	30 892	12 603	43 495	58 465	101 960	474 358	53 971	78 200	23 760	30	69
1990	31 173	13 052	44 225	58 722	102 947	465 395	53 127	78 302	24 645	31	68
1991	32 101	13 052	45 153	60 271	105 424	474 597	54 178	82 963	22 461	27	65
1992	32 415	13 987	46 402	61 871	108 273	476 450	54 389	86 631	21 642	25	63

(a) 1920-55: Figures are approximate, computed using actual statistics Canada data for stations generating energy for sale to which have been added estimates for stations generating entirely for own use. 1920-55: Canadian Energy Prospects (Royal Commision on Canada's Economic Prospects), John Davis, 1957. 1956-81: Statistics Canada Publication 57-202

(b) Average Demand = Energy Consumption/8760 (hrs/yr).

(c) Statistics Canada Publication, 57-204.

(d) Reserve Margin = (Installed Capacity - Peak Demand) ÷ Peak Demand

(e) Load Factor = Average Demand/Peak Demand

Source Statistics Canada and Department of Natural Resources Canada

Table A2.
Installed Generating Capacity, 1992

	Hydro	Nuclear	Conventional Thermal	Total	% of Canadian Total
	....	....	(MW)	....	....
Newfoundland	6 650	0	797	7 447	6.88
P.E.I.	0	0	122	122	0.11
Nova Scotia	390	0	1 940	2 330	2.15
New Brunswick	903	680	2 454	4 037	3.73
Quebec	29 099	685	1 320	31 104	28.73
Ontario	7 191	12 622	14 156	33 969	31.37
Manitoba	4 498	0	415	5 312	4.91
Saskatchewan	836	0	2 308	3 144	2.90
Alberta	733	0	7 247	7 980	7.37
British Columbia	10 849	0	1 640	12 489	11.53
Yukon	77	0	58	135	0.13
N.W.T.	51	0	153	204	0.19
Canada *(totals as of Dec. 31/92)*:	61 676	13 987	32 610	108 273	100.00
Percentage Total:	57.14	12.92	29.94	100.00	
Net Additions during 1992:	1 600	935	314	2 849	

Source: Department of Natural Resources Canada

Table A3.
Conventional Thermal Capacity by Principal Fuel Type, 1992* (MW)

Steam					
	Coal	Oil	Gas	Other	Total
Newfoundland	0	538	0	5	543
P.E.I.	0	70	0	0	70
Nova Scotia	1 332	382	0	19	1 733
New Brunswick	418	1 385	0	87	1 890
Quebec	0	615	8	5	628
Ontario	10 653	2 200	358	106	13 317
Manitoba	369	0	4	23	396
Sask.	1 831	21	278	22	2 152
Alberta	4 861	0	1 546	336	6 743
British Columbia	0	66	963	367	1 396
Yukon	0	0	0	0	0
N.W.T.	0	0	0	0	0
Canada	**19 464**	**5 277**	**3 157**	**970**	**28 868**

Gas Turbine			
	Oil	Gas	Total
Newfoundland	170	0	170
P.E.I.	41	0	41
Nova Scotia	205	0	205
New Brunswick	548	0	548
Quebec	558	0	558
Ontario	505	322	827
Manitoba	0	0	0
Sask.	0	155	155
Alberta	0	464	464
British Columbia	100	46	146
Yukon	0	0	0
N.W.T.	0	20	20
Canada	**2 127**	**1 007**	**3 134**

* *Preliminary figures as of December 31, 1992.*
(Numbers may not total due to rounding).

Table A3. continued

Internal Combustion			
	Oil	Gas	Total
Newfoundland	84	0	84
P.E.I.	11	0	11
Nova Scotia	2	0	2
New Brunswick	16	0	16
Quebec	134	0	134
Ontario	4	8	12
Manitoba	19	0	19
Sask.	1	0	1
Alberta	18	22	40
British Columbia	77	21	98
Yukon	58	0	58
N.W.T.	133	0	133
Canada	**557**	**51**	**608**

All Conventional Thermal					
	Coal	Oil	Gas	Other**	Total
Newfoundland	0	792	0	5	797
P.E.I.	0	122	0	0	122
Nova Scotia	1 332	589	0	19	1 940
New Brunswick	418	1 949	0	87	2 454
Quebec	0	1 307	8	5	1 320
Ontario	10 653	2 709	688	106	14 156
Manitoba	369	19	4	23	415
Sask.	1 831	22	433	22	2 308
Alberta	4 861	18	2 032	336	7 247
British Columbia	0	243	1 030	367	1 640
Yukon	0	58	0	0	58
N.W.T.	0	133	20	0	153
Canada	**19 464**	**7 961**	**4 215**	**970**	**32 610**

** *Mainly wood wastes and black liquor.*

Source: Electricity Branch, Department of Natural Resources Canada

Table A4.
Electrical Energy Production by Principal Fuel Type, 1992 (GWh)

	Conventional Thermal*							
	Coal	Oil	Gas	Sub-total	Nuclear	Hydro	Other	Total
Newfoundland	0	1 801	0	1 801	0	34 880	0	36 681
P.E.I.	0	34	0	34	0	0	0	34
Nova Scotia	5 994	2 676	0	8 670	0	896	156	9 722
New Brunswick	1 195	6 687	0	7 882	4 835	2 972	273	15 962
Quebec	0	1 125	0	1 125	4 600	141 352	0	147 077
Ontario	27 470	649	2 338	30 457	66 587	39 719	1 755	138 518
Manitoba	269	3	7	279	0	26 434	50	26 763
Sask.	9 957	46	891	10 894	0	3 055	178	14 127
Alberta	38 677	0	5 888	44 565	0	1 585	1 370	47 520
British Columbia	0	338	1 669	2 007	0	60 555	1 496	64 058
Yukon	0	61	0	61	0	419	0	480
N.W.T.	0	219	95	314	0	267	0	581
Canada	**83 562**	**13 639**	**10 888**	**108 089**	**76 022**	**312 134**	**5 278**	**501 523**

	Percentage of Total Generation	Percentage Generated by Utilities	Percentage Generated by Industry
Newfoundland	7.31	98.64	1.36
P.E.I.	0.01	100.00	.00
Nova Scotia	1.94	96.07	3.93
New Brunswick	3.18	95.81	4.19
Quebec	29.32	88.11	11.89
Ontario	27.62	97.13	2.87
Manitoba	5.33	99.78	0.22
Sask.	2.82	97.10	2.90
Alberta	9.48	92.32	7.68
British Columbia	12.77	80.40	19.60
Yukon	0.10	100.00	.00
N.W.T.	0.12	79.17	20.83
Canada	**100.00**	**92.06**	**7.94**

** The conventional thermal breakdown is estimated.*
Source: Statistics Canada and Department of Natural Resources Canada

Table A5.
Provincial Electricity Imports and Exports (GWh), 1992

		Interprovincial Trade			International Trade*			
Province	Year	Exports	Imports	Net Exports	Exports	Imports	Net Exports	Total Net Exports
Newfoundland	1992	25 985	-	25 985	-	-	-	25 985
	1991	26 366	-	26 366	-	-	-	26 366
	1990	26 164	-	26 164	-	-	-	26 164
	1989	24 367	-	24 367	-	-	-	24 367
	1988	30 727	-	30 727	-	-	-	30 727
Prince Edward Island	1992	-	738	-738	-	-	-	-738
	1991	-	690	-690	-	-	-	-690
	1990	-	672	-672	-	-	-	-672
	1989	-	622	-622	-	-	-	-622
	1988	-	486	-486	-	-	-	-486
Nova Scotia	1992	67	233	-166	-	-	-	-166
	1991	50	444	-394	-	-	-	-394
	1990	116	365	-249	-	-	-	-249
	1989	341	441	-100	-	-	-	-100
	1988	166	186	-20	-	-	-	-20
New Brunswick	1992	4 345	3 925	420	1775	116	1 659	2075
	1991	2 542	3 433	-891	3 092	79	3 013	2 122
	1990	2 153	2 775	-622	4 277	162	4 115	3 493
	1989	2 014	2 307	-293	4 640	264	4 376	4 083
	1988	981	2 856	-1 875	5 191	190	5 001	3 126
Quebec	1992	4 509	29 527	-25 018	8 877	1 388	7 489	-17 529
	1991	4 112	27 883	-23 771	5 959	730	5 229	-18 542
	1990	3 349	27 414	-24 065	3 403	1 188	2 215	-21 851
	1989	2 998	25 399	-22 401	5 438	1 001	4 437	-17 964
	1988	4 979	31 079	-26 100	11 863	86	11 777	-14 323

Table A5. continued

Province	Year	Interprovincial Trade: Exports	Interprovincial Trade: Imports	Interprovincial Trade: Net Exports	International Trade*: Exports	International Trade*: Imports	International Trade*: Net Exports	Total Net Exports
Ontario	1992	201	2 203	-2 002	5 303	4 166	1 137	-865
	1991	109	2 211	-2 102	4 771	3 674	1 097	-1 005
	1990	140	2 326	-2 186	2 050	13 339	-11 289	-13 475
	1989	91	2 335	-2 244	4 314	7 864	-3 550	-5 794
	1988	65	2 827	-2 762	7 439	2 611	4 828	2 066
Manitoba	1992	3 113	965	2 148	6 250	11	6 239	8 387
	1991	2 634	975	1 659	3 478	289	3 189	4 848
	1990	2 694	1 053	1 641	2 050	991	1 059	2 700
	1989	2 474	1 126	1 348	1 284	1 447	-163	1 185
	1988	1 908	1 126	782	628	1 969	-1 341	-559
Saskatchewan	1992	1 083	1 584	-501	138	100	38	-463
	1991	998	1 268	-270	148	120	28	-242
	1990	1 086	1 152	-66	121	107	14	136
	1989	1 130	1 213	-83	72	123	-51	-134
	1988	1 109	1 369	-260	57	315	-258	-518
Alberta	1992	2 016	418	1 598	-	2	-2	1 596
	1991	1 064	678	386	-	3	-3	383
	1990	1 336	500	836	-	3	-3	833
	1989	2 519	258	2 261	-	3	-3	2 258
	1988	1 218	369	849	-	-	-	849
British Columbia	1992	267	1 993	-1 726	9 206	692	8 514	6 788
	1991	655	948	-293	7 070	1 324	5 746	5 453
	1990	461	1 242	-781	6 228	1 991	4 237	3 456
	1989	242	2 477	-2 235	6 341	2 024	4 317	2 082
	1988	364	1 219	-855	8 851	1 132	7 719	6 864

Table A5. continued

Province	Year	Interprovincial Trade Exports	Interprovincial Trade Imports	Interprovincial Trade Net Exports	International Trade* Exports	International Trade* Imports	International Trade* Net Exports	Total Net Exports
Yukon	1992							
	1991	-	-	-	-	-	-	-
	1990	-	-	-	-	-	-	-
	1989	-	-	-	-	-	-	-
	1988	-	-	-	-	-	-	-
Northwest Territories	1992							
	1991	-	-	-	-	-	-	-
	1990	-	-	-	-	-	-	-
	1989	-	-	-	-	-	-	-
	1988	-	-	-	-	-	-	-
Canada	1992				31 549	6 476	25 073	25 073
	1991	-	-	-	24 518	6 219	18 299	18 299
	1990	-	-	-	18 130	17 781	349	349
	1989	-	-	-	22 089	12 724	9 365	9 365
	1988	-	-	-	34 029	6 305	27 724	27 724

** Includes exchanges.*

Source: National Energy Board

Table A6.
Canadian Electricity Exports by Exporter and Importer, 1992*

EXPORTER	IMPORTER	Revenue ($ 000)	Quantity (GWh)
Fraser Inc.	Fraser Paper Ltd. (Maine)	18 490	327
Maine & New Brunswick Electrical Power Co. Ltd.	Maine Public Service Co. (Maine)	2 642	99
NB Power	Maine Public Service Co. (Maine)	5 589	202
NB Power	Eastern Maine Electric Cooperative Inc. (Maine)	5 264	70
NB Power	Maine Electric Power (Maine)	9 895	322
NB Power	Massachusetts Municipal Wholesale Electric Co. (Massachusetts)	46 566	757
Hydro-Québec	Vermont Joint Owners (Vermont)	43 072	705
Hydro-Québec	Vermont Dept. of Public Service (Vermont)	33 989	1 080
Hydro-Québec	New England Power Pool (New England)	119 407	5 414
Hydro-Québec	Niagara Mohawk Power Corp. (New York)	2 538	72
Hydro-Québec	New York Power Authority (New York)	70 148	1 555
Canadian Niagara	Niagara Mohawk Power Corp. (New York)	493	22
Ontario Hydro	Vermont Dept. of Public Service (Vermont)	8	0
Ontario Hydro	Niagara Mohawk Power Corp. (New York)	13 227	458
Ontario Hydro	New York Power Authority (New York)	25 562	949
Ontario Hydro	New York Power Pool (New York)	6 367	3 194
Ontario Hydro	Detroit Edison Co. (Michigan)	1 586	82
Ontario Hydro	Minnesota Power and Light	1 635	26
Manitoba Hydro	Northern States Power Co. (Minnesota)	41 558	2 796
Manitoba Hydro	Otter Tail Power Co. (Minnesota)	10 581	567
Manitoba Hydro	United Power Association (Minnesota)	84	4
Manitoba Hydro	Minnesota Power & Light Co. (Minnesota)	9 910	698
Manitoba Hydro	Minnkota Power Cooperative Inc. (North Dakota)	9 616	603
Sask. Power	Basin Electric Power Cooperative (North Dakota)	1 697	138
Cominco Ltd.	Puget Sound Power & Light Co. (Washington)	121	5
Cominco Ltd	Washington Water Power Co. (Washington)	544	18
Cominco Ltd.	Portland General Electric Co. (Oregon)	4 029	172
Cominco Ltd.	Montana Power Co. (Montana)	259	13
Cominco Ltd.	Sierra Pacific Power Co. (Nevada)	64	2
Cominco Ltd.	Idaho Power Co. (Idaho)	2 741	106
Cominco Ltd.	Bonneville Power Administration (Washington)	6 524	272
Cominco Ltd.	Pacificorp (Washington)	2 183	78
Cominco Ltd.	Pacificorp (Oregon)	120	6
Cominco Ltd.	Bonneville Power Administration (California)	1 023	53
Cominco Ltd.	Sacramento Municipal	476	18
Cominco Ltd.	Pacific Gas & Electric	135	5
B.C. Hydro	Seattle City Light (Washington)	2 183	78
B.C. Hydro	Puget Sound Power & Light Co. (Washington)	1 243	27
B.C. Hydro	Washington Water Power Co. (Washington)	1 331	52

Table A6. continued

EXPORTER	IMPORTER	Revenue ($ 000)	Quantity (GWh)
B.C. Hydro	Portland General Electric Co. (Oregon)	17 951	699
B.C. Hydro	Idaho Power Co. (Idaho)	4 098	157
B.C. Hydro	Montana Power Co. (Montana)	82	4
B.C. Hydro	Bonneville Power Administration (Washington)	102 983	5 510
B.C. Hydro	City of Los Angeles (California)	1 326	53
B.C. Hydro	Sierra Pacific Power Co. (Washington)	58	2
B.C. Hydro	Snohomism PUD	87	2
B.C. Hydro	Pacificorp (Washington)	694	25
B.C. Hydro	Pacific Gas & Electric (Washington)	24 170	1 005
B.C. Hydro	Pacificorp (Oregon)	303	13
B.C. Hydro	Bonneville Power Administration (California)	20 591	881
B.C. Hydro	Bonneville Power Administration (Nevada)	555	16
B.C. Hydro	Sierra Pacific (Nevada)	40	2

* *Excludes border accommodations*

Source: National Energy Board

Table A7.
Generation Capacity by Type (MW)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
NEWFOUNDLAND							
Total end 1991	543.00	170.39	83.43	-	796.82	6 649.79	7446.61
Changes 1992	-	-	-	-	-	-	-
Total end 1992	543.00	170.39	83.43	-	796.82	6 649.79	7 446.61
Additions proposed							
1993	-	25.00	-	-	25.00	-	25.00
1994	-	-	-	-	-	6.00	6.00
Total end 1993	543.00	195.39	83.43	-	821.82	6 655.79	7 477.61
PRINCE EDWARD ISLAND							
Total end 1991	70.50	40.45	11.14	-	122.09	-	122.09
Changes 1992	-	-	-	-	-	-	-
Total end 1992	70.50	40.45	11.14	-	122.09	-	122.09
Additions proposed							
1996	-	24.00	-	-	24.00	-	24.00
Total end 1996	70.50	64.45	11.14	-	146.09	-	146.09
NOVA SCOTIA							
Total end 1991	1 733.62	205.00	1.50	-	1 940.12	390.00	2 330.12
Changes 1992	-	-	-	-	-	-	-
Total end 1992	1 733.62	205.00	1.50	-	1 940.12	390.00	2 330.12
Additions proposed							
1993	165.00	-	-	-	165.00	-	165.00
2005	165.00	-	-	-	165.00	-	165.00
2010	165.00	-	-	-	165.00	-	165.00
Total end 2010	2 228.62	205.00	1.50	-	2 435.12	390.00	2 825.12
NEW BRUNSWICK							
Total end 1991	1 888.98	548.38	16.34	680.00	2 453.70	903.03	4 036.73
Changes 1992	-	-	-	-	-	-	-
Total end 1992	1 888.98	548.38	16.34	680.00	2 453.70	903.03	4 036.73
Additions proposed							
1993	443.00	-	-	-	443.00	-	443.00
2001	-	100.00	-	-	100.00	-	100.00
2004	-	100.00	-	-	100.00	-	100.00
2005	-	100.00	-	-	100.00	-	100.00
2006	440.00	-	-	-	440.00	-	440.00
Total end 2006	2 771.98	848.38	16.34	680.00	3 636.70	903.03	5 219.73

Table A7.
Generation Capacity by Type (MW) (continued)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
QUEBEC							
Total end 1991	627.65	362.88	134.04	685.00	1809.57	28 093.21	29 902.78
Changes 1992	-	-	-	-	-	1 201.00	1 201.00
Total end 1992	627.65	362.88	134.04	685.00	1809.57	29 294.21	31 103.78
Additions proposed							
1993	-	195.00	-	-	195.00	723.00	918.00
1994	-	-	-	-	-	1 266.00	1 266.00
1995	-	-	-	-	-	656.00	656.00
1996	-	-	-	-	-	289.00	289.00
1998	-	-	-	-	-	465.00	465.00
1999	-	-	-	-	-	924.00	924.00
2000	-	-	-	-	-	615.00	615.00
2001	-	-	-	-	-	3 758.00	3 758.00
2002	-	-	-	-	-	1 948.00	1 948.00
2003	-	-	-	-	-	729.00	729.00
Total end 2003	627.65	557.88	134.04	685.00	2 004.57	41 142.21	43 146.78
ONTARIO							
Total end 1991	13 316.80	827.88	11.77	11 687.00	25 843.45	7 191.02	33 034.47
Changes 1992	-	-	-	935.00	935.00	-	935.00
Total end 1992	13 316.80	827.88	11.77	12 622.00	26 778.45	7 191.02	33 969.47
Additions proposed							
1993	-	-	-	1 870.00	1 870.00	10.00	1 880.0
1994	-	-	-			1.90	1.80
1995	-	-	-	-	-	2.50	2.50
1996	-	-	-	-	-	1.40	1.40
Total end 1996	13 316.80	827.88	11.77	14 492.00	28 648.45	7 206.82	35 855.17
MANITOBA							
Total end 1991	395.80	-	19.64	-	415.44	4 497.63	4 913.07
Changes 1992	-	-	-	-	-	399.00	388.00
Total end 1992	395.80	-	19.64	-	415.44	4 896.63	5 312.07
Additions proposed							
2009	-	-	-	-	-	175.00	175.00
2010	-	-	-	-	-	175.00	175.00
Total end 2014	395.80	-	19.64	-	415.44	5 246.63	5 662.07

Table A7.
Generation Capacity by Type (MW) (continued)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
SASKATCHEWAN							
Total end 1991	1 852.06	154.92	0.68	-	2 007.66	835.86	2 843.52
Changes 1992	300.00	-	-	-	300.00	-	300.00
Total end 1992	2 152.06	154.92	0.68	-	2 307.66	835.86	3 143.52
ALBERTA							
Total end 1991	6 742.72	464.10	40.08	-	7 246.50	733.70	7 980.60
Changes 1992	-	-	-	-	-	-	-
Total end 1992	6 742.72	464.10	40.08	-	7 246.50	733.70	7 980.60
Additions proposed							
1993	-	34.00	-	-	34.00	-	34.00
1994	406.00	-	-	-	406.00	-	406.00
1996	30.00	-	-	-	30.00	-	30.00
Total end 1996	7 178.72	498.10	40.08	-	7 716.50	733.70	8 450.60
BRITISH COLUMBIA							
Total end 1991	1 396.16	145.70	98.37	-	1 640.21	10 849.07	12 489.30
Changes 1992	-	-	-	-	-	-	-
Total end 1992	1 396.16	145.70	98.37	-	1 640.21	10 849.07	12 489.30
Additions proposed							
2000	-	-	-	-	-	196.00	196.00
2001	-	-	-	-	-	190.00	190.00
2002	-	-	-	-	-	190.00	190.00
2007	-	-	-	-	-	80.00	80.00
2008	-	-	-	-	-	160.00	160.00
2011	-	-	-	-	-	75.00	75.00
2012	-	-	-	-	-	75.00	75.00
Total end 2012	1 396.16	145.70	98.37	-	1 640.21	11 815.07	13 455.30
YUKON							
Total end 1991	-	-	52.90	-	52.90	76.75	129.65
Changes 1992	-	-	5.00	-	5.00	-	5.00
Total end 1992	-	-	57.90	-	57.90	76.75	134.65
Additions proposed							
1993	-	-	1.00	-	1.00	-	1.00
1994	-	-	0.80	-	0.80	-	0.80
Total end 1994	-	-	59.70	-	59.70	76.75	136.45

Table A7.
Generation Capacity by Type (MW) (continued)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
NORTHWEST TERRITORIES							
Total end 1991	-	19.50	124.51	-	144.01	50.66	194.67
Changes 1992	-	-	9.00	-	9.00	-	9.00
Total end 1992	-	19.50	133.51	-	153.01	50.66	203.67
Additions proposed							
1993	-	-	8.20	-	8.20	-	8.20
1994	-	-	1.00	-	1.00	-	1.00
1995	-	-	1.00	-	1.00	-	1.00
Total end 1994	-	19.50	143.71	-	163.21	-	213.87
CANADA							
Total end 1991	28 567.29	2 939.20	594.38	13 052.00	44 152.87	60 271.08	105 423.95
Changes 1992	300.00	-	14.00	935.00	1 245.00	1 600.00	2 849.00
Total end 1992	28 867.29	2 939.20	608.38	13 987.00	46 401.87	61 871.08	108 272.95
Additions proposed							
1993	608.00	254.00	9.20	1870.00	2 741.20	733.00	3 474.20
1994	406.00	-	1.80	-	407.80	1 292.99	1 700.70
1995	-	-	1.00	-	1.00	658.50	659.50
1996	30.00	24.00	-	-	54.00	290.40	344.40
1997	-	-	-	-	-	-	-
1998	-	-	-	-	-	465.00	465.00
1999	-	-	-	-	-	924.00	924.00
2000	-	-	-	-	-	615.00	615.00
2001	-	100.00	-	-	100.00	3 758.00	3 858.00
2002	-	-	-	-	-	2 138.00	2 138.00
2003	-	-	-	-	-	729.00	729.00
2004	-	100.00	-	-	100.00	-	100.00
2005	165.00	100.00	-	-	265.00	-	265.00
2006	440.00	-	-	-	440.00	-	440.00
2007	-	-	-	-	-	80.00	80.00
2008	165.00	-	-	-	165.00	160.00	325.00
2009	-	-	-	-	-	175.00	175.00
2010	165.00	-	-	-	165.00	175.00	340.00
2011	-	-	-	-	-	75.00	75.00
2012	-	-	-	-	-	75.00	75.00
Total end 2014	30 846.29	3 517.20	620.38	15 857.00	50 840.87	72 748.88	123 589.75

Source: Natural Resources Canada

Table A8.
Installed Generating Capacity Expansion in Canada by Station. Major 1992 Additions and 1993-2012 Projections.

Province and Station	Type*	1992 Additions	Completion Date	Additions Proposed	Status*	Plant Capacity
		(MW)		(MW)		(MW)
NEWFOUNDLAND						
Port aux Basques	GT(o)		1993	25	C	25
Rose Blanche	H		1995	6	C	6
PRINCE EDWARD ISLAND						
Charlottetown	GT(o)		1996	24	P	24
NOVA SCOTIA						
Point Aconi	S(c)		1993	165	C	
Point Aconi	S(c)		2005	165	P	
Point Aconi	S(c)		2010	165	P	495
NEW BRUNSWICK						
Belledune	S(c)		1993	443	C	
			2006	440	P	883
Combustion Turbine	GT(o)		2001	100	P	100
Combustion Turbine	GT(o)		2004	100	P	100
Combustion Turbine	GT(o)		2005	100	P	100
QUEBEC						
La Forge-1	H		1993	2 x 137	C	
			1994	4 x 136	C	817
La Forge-2	H		1996	145	P	
			1996	144	P	289
Manic-1[1]	H		2006	134	P	134
Brisay	H		1993	2 x 191	C	382
Outardes 4	H		2002	350	P	350
Outardes 3	H		2002	2 x 239	P	478
Outardes 2	H		2002	282	P	282
Manic-2	H		1999	322	P	1 378
Manic-3	H		1998	2 x 301	P	1 803
Manic-5[1]	H	56	1992			
			1993	67	C	
			1994	67	C	2 052

[1] *Uprating of existing units*

Table A8.
Installed Generating Capacity Expansion in Canada by Station.
Major 1992 Additions and 1993-2012 Projections (continued)

Province and Station	Type*	1992 Additions	Completion Date	Additions Proposed	Status*	Plant Capacity
		(MW)		(MW)		(MW)
QUEBEC (cont'd)						
LG-1	H		1994	3 x 109	C	
			1994	2 x 110	C	
			1995	4 x 109	C	
			1995	2 x 110	C	1 312
LG-2A	H	950	1992			
Ste-Marguerite-3	H		2001	2 x 393	P	786
Grande-Baleine-1	H		2001	2 x 411	P	
			2001	412	P	
			2001	2 x 412	P	2 058
Grande-Baleine-2	H		2001	3 x 180	P	540
Grande-Baleine-3	H		2001	187	P	
			2001	188	P	560
			2001	185	P	
Eastmain-1	H		1998	3 x 155	P	465
Future peaking	GT(d)		2007	400	P	
			2008	300	P	
			2009	300	P	
			2010	100	P	1 100
Bécancour	H	195			P	
			1993	195	C	390
Rapid des Coeurs	H		2000	2 x 174	P	348
Chutes Chaudieres	H		2000	125	P	
			2000	124	P	249
Ashuapmushuan-4	H		2003	303	P	303
Mercier	H		2001	90	P	90
Kipawa	H		2001	115	P	115
ONTARIO						
Darlington	N		1993	2 x 881	C	3 524
MANITOBA						
Wuskwatim	H		2009	2 x 87.5	P	
			2010	2 x 87.5	P	350
SASKATCHEWAN						
NONE						

Table A8.
Installed Generating Capacity Expansion in Canada by Station. Major 1992 Additions and 1993-2012 Projections (continued)

Province and Station	Type*	1992 Additions	Completion Date	Additions Proposed	Status*	Plant Capacity
		(MW)		(MW)		(MW)
ALBERTA						
Genesee	S(c)		1994	406	C	812
Medicine Hat	GT(g)		1993	34	C	34
	S(c)		1996	30	P	30
BRITISH COLUMBIA						
Seven Mile 4	H		2000	1 x 196	P	785
Waneta	H		2001	2 x 190	P	380
Keeneleyside	H		2007	3 x 80	P	240
Brilliant	H		2011	2 x 75	P	450
YUKON						
Dawson	IC		1993	1.0	C	5.2
McIntyre	H		1994	0.8	C	1.5
NORTHWEST TERRITORIES						
Ramkin Inlet	IC		1993	1.0	C	1.00
Fort Good Hope	IC		1993	0.5	C	1.00
Yellowknife	IC		1993	3.3	C	3.30
Arctic Red River	IC		1993	0.2	C	
Clyde River	IC		1993	0.5	C	
Aklaaik	IC		1993	0.7	C	
Arviat	IC		1993	2.0	C	
Fort Norman	IC		1994	0.5	P	
Repulse Bay	IC		1994	0.5	P	
Baber Lake	IC		1995	1.0	P	

***Legend**

H	Hydro	IC	Internal combustion
S(c)	Steam (coal)	GT	Gas turbine
N	Nuclear	I	Installed
P	Planned	C	Under construction
GT(o)	Gas turbine (oil)		
GT(g)	Gas turbine (natural gas)		
GT(d)	Gas-turbine (diesel)		

Source: Natural Resources Canada

Federal Environmental Standards and Guidelines

Recent amendments to the National Energy Board Act specify that the Board, in assessing applications for exports and international transmission lines, consider the potential impacts of projects on the environment. (See Chapter 3 for a detailed discussion of the regulatory process.) This appendix provides a brief overview of some federal environmental standards that, in addition to provincial environmental protection measures, may be particularly relevant to the assessment of such impacts.

Federal environmental standards are those that have been authorized or endorsed by the federal government and that apply where a project affects an area of explicit federal jurisdiction, such as navigable waters or migratory birds. Following a general discussion of types of environmental standards, the relevant federal standards are summarized briefly.[1]

Types of Environmental Standards

Environmental standards are norms established with the overall objective of protecting both human and environmental health. For the purposes of this report, the term "environmental standards" will be used as a general reference to all environmental guidelines, objectives, limits, criteria and codes of practice. Federal environmental standards are grouped into three general categories for the purposes of discussion: ambient standards, emission standards and other standards.

[1] Greater detail on federal legislation, initiatives and standards may be obtained by contacting the Electricity Branch, Department of Natural Resources Canada.

Ambient Standards

Ambient standards are quantitative or qualitative statements describing a level of environmental quality that, if maintained in the "ambient" or open environment, will normally protect environmental and human health. Such standards generally specify concentrations of substances, or physical characteristics such as water temperature. Federal ambient standards normally have no legal force in themselves. They describe a level of environmental quality that may apply to specific designated regions, or to all regions of Canada. They serve as the goals or objectives towards which pollution-control initiatives, including legislation and regulations specifying emission standards, are directed.

Emission Standards

Emission standards refer to a limit on the quantity or quality of substances that may be released from industrial processes. They usually specify a release rate or maximum concentration of a harmful substance that may be present in the emission as it emerges from its source: a smokestack, pipeline or landfill drainage system. Federal emission standards, which are given force of law under regulations, are considered to be the minimum acceptable requirements for any industrial undertaking. More stringent emission standards may be required to meet appropriate ambient standards at a particular site.

Other Standards

Other standards include programs and legislation that provide for a wide variety of environmental protection measures, in addition to ambient or emission standards. Examples include the Environmental Codes of Practice for Steam Electric Power Generation and the Canadian Environmental Protection Act.

Overview of Federal Standards

1.1 Ambient Standards: Air

National Ambient Air Quality Objectives

The *National Ambient Air Quality Objectives*, published under the authority of the Canadian Environmental Protection Act (CEPA) of 1988, specifies criteria for tolerable, acceptable and desirable levels of sulphur dioxide, nitrogen oxides, particulate matter, ozone and carbon monoxide in the open or ambient atmosphere.

Intergovernmental Agreements

Ambient standards are one method of implementing intergovernmental agreements to reduce and control air pollution. (For a general discussion of intergovernmental agreements on air pollution, see section 3.3 of this appendix.)

1.2 Ambient Standards: Water

Water Quality Guidelines

The Canadian Water Quality Guidelines, published by the Canadian Council of Ministers of the Environment (CCME), is an inventory of "water quality objectives" (ambient standards) suitable for different water uses in Canada, such as aquatic life, industrial pro-cesses, human consumption, recreational use and agricultural irrigation. These standards differ depending on the different water uses and must therefore be adapted to meet regional water quality needs. These standards are developed from existing guidelines where appropriate, such as the *Guidelines for Canadian Drinking Water Quality*, established by the Federal-Provincial Subcommittee on Drinking Water.

Intergovernmental Agreements

Canada has entered into an agreement with the United States (The Great Lakes Water Quality Agreement) to restore and maintain the water quality of the Great Lakes basin. To assist in meeting the goals of the Agreement, environmental quality objectives (ambient standards) were established for these waters.

Other regional ambient standards may be developed under federal-provincial agreements and programs enacted pursuant to the Canada Water Act

2.1 Emission Standards: Air

Thermal Power Generation Emissions -- National Guidelines for New Stationary Sources

These guidelines, published under the authority of CEPA, and revised in 1993, are technology-based air emission standards for new fossil-fuelled electric generating stations. They are generic emission limitations recommended as minimum national standards that should be adopted by utilities and provincial governments. Criteria specified in the guidelines include those for sulphur dioxide, nitrogen oxides and particulate matter emissions, as well as for opacity (visibility standards) and continuous emission monitoring.

2.2 Emission Standards: Water

The Environmental Codes of Practice for Steam Electric Power Generation

See Other Federal Standards, section 3.1, for a general description of the Codes of Practice.

The Design Phase Code of Practice recommends technology-based minimum waste water emission limitations. These standards specify effluent criteria for metals, oil and grease, chlorine, suspended solids and acidity, to minimize the total amount of contaminants discharged to surface waters. These criteria are of concern to aquatic and human life.

Federal Legislation: the Fisheries Act, the Canada Water Act, and the Migratory Birds Act

The Fisheries Act prohibits the deposit of deleterious substances in any waters inhabited by fish. Regulations may limit the deposit of certain types of waste or substances in specific quantities and concentrations. Provisions are supported by Environment Canada's *Environmental Codes of Practice for Steam Electric Power Generation*. The Act also includes a broad range of environmental protection measures that cannot be adequately discussed in this short summary.

The Canada Water Act provides the federal government with the authority to regulate the emission of substances in designated "water quality management" areas. No regulations for water emissions have been implemented under this Act. The Act also provides the federal government with the authority to enter agreements with the provinces for water quality management.

Regulations pursuant to the Migratory Birds Act prohibit, in certain circumstances, the dumping of substances harmful to migratory birds in any water or area populated by these birds in Canada.

Other Federal Standards

3.1 Environmental Codes of Practice for Steam Electric Power Generation

The *Environmental Codes of Practice*, developed by a federal-provincial government and industry task force established by Environment Canada, contain recommendations judged to be reasonable and practical measures that can be taken to preserve the quality of the environment affected by fossil- and nuclear-fuelled electric power generation. Codes of practice have been published for the design, siting, construction, operation and decommissioning phases of steam electric power generation projects. Although the design and siting phase codes have no legal status, the construction, operation and decommissioning phase codes have been published under the authority of CEPA.

The various phases of the codes of practice, although treated in separate documents, are interdependent. To ensure environmental protection throughout the life of a steam electric power generating facility, the Codes should be considered as a whole.

3.2 Federal Legislation for the Control of Harmful Substances

The Canadian Environmental Protection Act provides authority for the control of harmful or toxic substances at any stage of the life-cycle of these substances, including development, manufacturing, storage, transportation, use and disposal. The Act specifies that the Minister of the Environment may develop environmental objectives (ambient standards), release guidelines (emission standards) and codes of practice, as well as enforceable regulations based on these and other environmental standards. Regulations include standards for the storage and disposal of polychlorinated biphenyls (PCBs).

The Transportation of Dangerous Goods Act authorizes the creation and enforcement of safety standards for transport, preparation for transport, and the related handling of dangerous goods (including PCBs and radioactive substances).

The Pest Control Products Act authorizes the development and enforcement of safety standards for the storage, handling and use of pesticides.

3.3 Intergovernmental Air Pollution Agreements

Canada is a signatory to three international protocols of the United Nations Economic Commission for Europe (ECE), under the 1979 Convention on Long-Range Transboundary Air Pollution. The sulphur protocol (1985) commits signatories to reduce national sulphur dioxide emissions by 30 per cent of 1980 levels by 1993. The nitrogen oxides protocol (1988) commits signatories to freeze national nitrogen oxides emissions at 1987 levels by 1994. The protocol on volatile organic compounds (VOCs) (1991) commits signatories to freeze national VOC emissions at 1988 levels by 1999, and, for high ozone regions, to reduce VOC emissions by 30 per cent of 1988 levels by 1999.

The protocol for the reduction of sulphur dioxide emissions has been implemented in Canada by individual agreements between the Government of Canada and the seven easterly provinces, to reduce emissions of sulphur dioxide by approximately 40 per cent of actual 1980 emissions by 1994. Consistent with the international protocol on NOx and VOCs, and with the Canadian goal of reducing ozone levels to the ambient air quality objective of 82 parts per billion, the Canadian Council of Ministers of the Environment (CCME) has developed a comprehensive plan of action for the further management of nitrogen oxides and volatile organic compound emissions in Canada.

On March 13, 1991 the governments of Canada and the United States signed an agreement on air quality (the Air Quality Accord). Among other things, Canada agreed to:

- Cap SO_2 emissions in the 7 easternmost provinces at 2.3 million tonnes per year from 1995 to 1999.

- Achieve a permanent national cap of 3.2 million tonnes per year by 2000.

- Reduce annual emissions of NOx from stationary sources by 100 000 tonnes per year below the year 2000 forecast level of 970 000 tonnes per year.

- Develop, by January 1, 1995, further annual national emission reduction requirements from stationary sources to be achieved by 2000 and/or 2005.

- By January 1, 1995, estimate SO_2 and NOx emissions from each new existing electric utility unit greater than 25 MW, using a method of comparable effectiveness to continuous emission monitoring.

- Assess, notify and mitigate against significant possible transboundary air pollution impacts arising from new projects.

Federal/provincial agreements are being renegotiated in 1993 to put the first of the above points of agreements into effect.

3.4 General Environmental Standards for Nuclear Power Generation: Atomic Energy Control Board

See Chapter 3 for a general discussion of the regulatory function of the Atomic Energy Control Board (AECB).

The AECB's standards for licensing and monitoring nuclear facilities include regulations pursuant to the Atomic Energy Control Act for limiting radiation dosage to the public, and transportation standards for packaging and marking nuclear substances. The Board receives advice on environmental standards from Environment Canada and frequently conducts its licensing activities under a joint regulatory process involving federal and provincial environment authorities. The AECB coordinates its regulatory activities with the federal Environmental Assessment and Review Process (EARP) and any provincial environ-

mental review process that may be required for nuclear facilities.

3.5 General Environmental Standards for Electricity Generation and Transmission for Export: National Energy Board

See Chapter 3 for details of the National Energy Board's regulatory process.

Applicants for a permit for an export of electricity or for an international transmission line are required to submit information to the National Energy Board on the potential environmental impacts of the export of the line. The Board will apply the procedures specified in the federal EARP Guidelines Order in determining whether to recommend designating an application for the licensing or certification process. When a licence hearing is necessary, applicants may be required to undertake a detailed analysis of the project, including among other things, environmental considerations.

3.6 Federal Environmental Assessment and Review Process Guidelines Order

See Chapter 4 for details of the federal EARP.

The Guidelines Order sets out standard procedures that should be followed by federal government departments in conducting an initial screening of projects under their authority for significant environmental effects.

Appendix C

Prices Paid by Major Electrical Utilities for Independent Power Production in 1993

Major Electric Utility	Purchase Rates	Pricing Formula	Remarks
Newfoundland and Labrador Hydro	Isolated Areas: depends on system	Based upon "share the savings" principle up to a maximum of 90% of the avoided fuel cost.	Purchases for isolated areas are evaluated based on the size of the system under consideration.
	Interconnected Areas: Winter (November-March) Capacity: 4.50 ¢/kWh Energy: 3.58¢/kWh Summer (April-October) Capacity: 2.11¢/kWh Energy: 3.58¢/kWh Rates are in 1992$. The capacity rate shall be escalated by the CPI* to the date that the plant goes in service after which it is fixed for the term of the contract. The energy rate shall be escalated by the CPI.	Based upon Average Incremental Cost.	NLH released a "Request for Proposals" for 50 MW of hydraulic IPP** in 1991. Proposals must be small hydro generation projects with capacities not to exceed 15 MW. Projects shall have capacity factors in excess of 40%. Plant's earliest in-service date is late 1997.
Newfoundland Light and Power Co. Ltd.	Negotiable.	Negotiation up to the system incremental cost of generation (total avoided cost).	IPPs will be considered if they are identified as part of an integrated resource plan for the island. Energy from IPPs will be purchased anytime the negotiated price is less than the short-run marginal cost of production (i.e., fuel and variable O&M).
Maritime Electric	4.036¢/kWh (in 1992).	Average purchase price of economy energy from New Brunswick Power.	
Nova Scotia Power	Capacity: 2.79¢/kWh Energy : 3.60¢/kWh	Full avoided cost based on system simulations.	Contract term for 10 years. Plants on-line during 1993-94 fiscal year.
	Capacity: 3.68¢/kWh Energy: 3.60¢/kWh	Proxy unit used to develop rates. Proxy unit is a 3x165 MW CFB plant plus associated transmission.	Contract term for 33 years. Capacity rate is fixed for term. Energy rate is based on actual proxy unit fuel and operating and maintenance. Plants on-line during 1993-94 fiscal year.
NB Power	Non-Dedicated Energy: Rate varies monthly.	Avoided energy costs only.	90% of system decrement.
	Dedicated Capacity: on-peak: 5.5¢/kWh off-peak: 3.3¢/kWh	Avoided full cost.	There are performance requirements for winter operation (Dec.-Mar.) to qualify for full capacity payments.

Prices Paid by Major Electric Utilities for Independent Power Production in 1993 (continued)

Major Electric Utility	Purchase Rates	Pricing Formula	Remarks
	Capacity: $20.34/kW/mo Energy: 3.5¢/kWh	Avoided full cost but tied to Belledune actual fuel and O&M costs.	Capacity 5 MW.
Hydro-Québec	4.5¢/kWh (1993 $)	Avoided cost.	The price is for high tension (greater or equal to 69 kV) and will be adjusted by the Consumer Price Index at a maximum of 6% and at a minimum of 3%.
	4.7¢/kWh (1993 $)	Avoided cost.	The price is for an average tension (750 to 69 kV) and will be adjusted by the Consumer Price Index at a maximum of 6% and at a minimum of 3%.
Ontario Hydro	Projects up to 5 MW:		
	Option 1 - Basic purchase rate schedule offered to non-utility generators regardless of the fuel or technology used.	Avoided cost.	To qualify for Option 1, a non-utility generator would have to enter into a contract with Ontario Hydro for a typical term of 20 years.
	Winter peak: 6.32¢/kWh	Peak rates are based on Ontario Hydro's 20-year incremental capacity and energy costs.	All time-differentiated rates adjusted annually at Ontario's CPI.
	Winter off-peak: 2.26¢/kWh	Off-peak rates are based on incremental energy cost.	Capacity factor is not a criterion in setting the rates.
	Summer peak: 5.59¢/kWh Summer off-peak: 1.72¢/kWh		
	Option 2 - Premium rates to projects that use renewable resources or use high efficiency energy conversion technology.	In principle, the pricing formula is the same as Option 1 above.	
	Winter peak: 7.11¢/kWh Winter off-peak: 2.54¢/kWh Summer peak: 6.30¢/kWh Summer off-peak: 1.94¢/kWh		
	Occasional - Ontario Hydro will purchase electricity on an occasional basis from its customers.	Average system marginal cost.	
	Winter peak: 2.25¢/kWh Winter off-peak: 1.74¢/kWh Summer peak: 2.05¢/kWh Summer off-peak: 1.26¢/kWh		

Prices Paid by Major Electric Utilities for Independent Power Production in 1993 (continued)

Major Electric Utility	Purchase Rates	Pricing Formula	Remarks
	Projects delivering over 5 MW net.	Avoided cost.	To be reviewed project-by-project.
Manitoba Hydro	To be negotiated.		Policies have not been finalized.
SaskPower	Rates established by competitive bidding.	Avoided cost.	25 MW of NUG capacity for start-up in 1995.
TransAlta Utilities Alberta Power Edmonton Power and the City of Medicine Hat	5.2¢/kWh (fixed from 1990 to 1994) increasing to 6.0¢/kWh (fixed from 1995 to 1999) or 4.64¢/kWh starting in 1990, escalating with inflation.	Legislated rates.	These rates are applied to small power producers using renewable resources such as wind, hydro and biomass. Projects are up to 2.5 MW. A limited number of pilot projects in excess of 2.5 MW may be approved.
	Energy from non-traditional sources such as generators powered by flare gas or co-generators.	To be negotiated.	
B.C. Hydro	To be negotiated.	80% of B.C. Hydro's avoided cost. The purchase price from an IPP must be less than the cost of other B.C. Hydro options at the time.	Should B.C. Hydro decide to purchase electricity from the private sector, the amount of electricity supply would then be negotiated.

* CPI = Consumer Price Index
** IPP = Independent Power Producer

Source: Major electric utilities, March 1993

Definitions and Abbreviations

Alternating Current (AC):
A current that flows alternately in one direction and then in the reverse direction. In North America the standard for alternating current is 60 complete cycles each second. Such electricity is said to have a frequency of 60 hertz. Alternating current is used universally in power systems because it can be transmitted and distributed much more economically than direct current.

Base Load:
The minimum continuous load over a given period of time.

British Thermal Unit (BTu):
A unit of heat. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Capacity:
In the electric power industry, capacity has two meanings:

1. System Capacity: The maximum power capability of a system. For example, a utility system might have a rated capacity of 5000 megawatts, or might sell 50 megawatts of capacity (i.e., of power).

2. Equipment Capacity: The maximum power capability of a piece of equipment. For example, a generating unit might have a rated capacity of 50 megawatts.

Capacity Factor:
For any equipment, the ratio of the average load during some time period to the rated capacity.

Cogeneration:
A cogenerating system produces electricity and heat in tandem. Such systems have great potential in industry, where a significant requirement for electricity is coupled with a large demand for process steam.

Consumer Price Index (CPI):
A measure of the percentage change over time in the cost of purchasing a constant "basket" of goods and services. The basket consists of items for which there are continually measurable market prices, so that changes in the cost of the basket are due only to price movements.

Consumption:
Use of electrical energy, typically measured in kilowatt hours.

Conventional Generation:
Electricity that is produced at a generating station where the prime movers are driven by gases or steam produced by burning fossil fuels.

Current:
The flow of electricity in a conductor. Current is measured in amperes.

Demand Charge:
The component of a two-part price for electricity that is based on a customer's highest power demand reached in a specified period, usually a month, regardless of the quantity of energy used (e.g., $2.00 per kilowatt per month). The other component of the two-part price is the energy charge.

Direct Current (DC):
Current that flows continuously in the same direction (as opposed to alternating current). The current supplied from a battery is direct current.

Economy Energy:
Energy sold by one power system to another, to effect a saving in the cost of generation when the receiving party has adequate capacity to supply the loads from its own system.

Electrical Energy:
The quantity of electricity delivered over a period of time. The commonly used unit of electrical energy is the kilowatt-hour (kWh).

Electrical Power:
The rate of delivery of electrical energy and the most frequently used measure of capacity. The basic unit is the kilowatt (kW).

Energy Charge:
The component of a two-part price for electricity which is based on the amount of energy taken (e.g., 20 mills per kWh). The other component of the price is the demand charge.

Energy Source:
The primary source that provides the power that is converted to electricity. Energy sources include coal, petroleum and petroleum products, gas, water, uranium, wind, sunlight, geothermal, and other sources.

Firm Energy or Power:
Electrical energy or power intended to be available at all times during the period of the agreement for its sale.

Frequency:
The number of cycles through which an alternating current passes in a second. The North American standard is 60 cycles per second, known as 60 hertz.

Gigawatt (GW): One billion watts. (See Watt.)

Gigawatt hour (GW.h):
A unit of bulk energy. A million kilowatt hours. A billion watt hours.

Grid:
A network of electric power lines and connections.

Gross Domestic Product (GDP):
The total value of goods and services produced in Canada. GDP measured in constant dollars is defined as Real GDP.

Gross National Product (GNP):
The total value of production of goods and services measured at market prices.

Hertz (Hz):
The unit of frequency for alternating current. Formerly called cycles per second. The standard frequency for power supply in North America is 60 Hz.

Installed Capacity:
The capacity measured at the output terminals of all the generating units in a station, without deducting station service requirements.

Interruptible Energy or Power:
Energy or power made available under an agreement that permits curtailment or interruption of delivery at the option of the supplier.

Joule:
The international unit of energy. The energy produced by a power of one watt flowing for one second. The joule is a very small unit: there are 3.6 million joules in a kilowatt hour.

Kilovolt (kV): 1000 volts.

Kilowatt (kW):
The commercial unit of electric power; 1000 watts. A kilowatt can best be visualized as the total amount of power needed to light ten 100-watt light bulbs.

Kilowatt hour (kWh):
The commercial unit of electric energy; 1000 watt hours. A kilowatt hour can best be visualized as the amount of electricity consumed by ten 100-watt light bulbs burning for an hour. One kilowatt hour is equal to 3.6 million joules.

Load:
The amount of electric power or energy consumed by a particular customer or group of customers.

Load Factor:
The ratio of the average load during a designated period to the peak or maximum load in that same period. (Usually expressed in per cent.)

Megawatt (MW):
A unit of bulk power; 1000 kilowatts.

Megawatt hour (MW.h):
A unit of bulk energy; 1000 kilowatt hours.

Mill: 1/1000 of a dollar.

Net Exports:
Total exports minus total imports.

Nuclear Power:
Power generated at a station where the steam to drive the turbines is produced by an atomic process, rather than by burning a combustible fuel such as coal, oil or gas.

Peak Demand:
The maximum power demand registered by a customer or a group of customers or a system in a stated period of time such as a month or a year. The value may be the maximum instantaneous load or more, usually the average load over a designated interval of time, such as one hour, and is normally stated in kilowatts or megawatts.

Power System:
All the interconnected facilities of an electrical utility. A power system includes all the generation, transmission, distribution, transformation, and protective components necessary to provide service to the customers.

Primary Energy Consumption:
The amount of energy available to the final consumer, plus conversion losses and energy used by the energy supply industries themselves. (Conversion losses are losses in the processing of refined petroleum products, for example, or losses due to thermal and mechanical inefficiencies resulting from the conversion of fossil fuels - coal, oil and natural

gas - into electricity in thermal power generation).

Reserve Generating Capacity:
The extra generating capacity required on any power system over and above the expected peak load. Such a reserve is required mainly for two reasons: (i) in case of an unexpected breakdown of generating equipment; (ii) in case the actual peak load is higher than forecast.

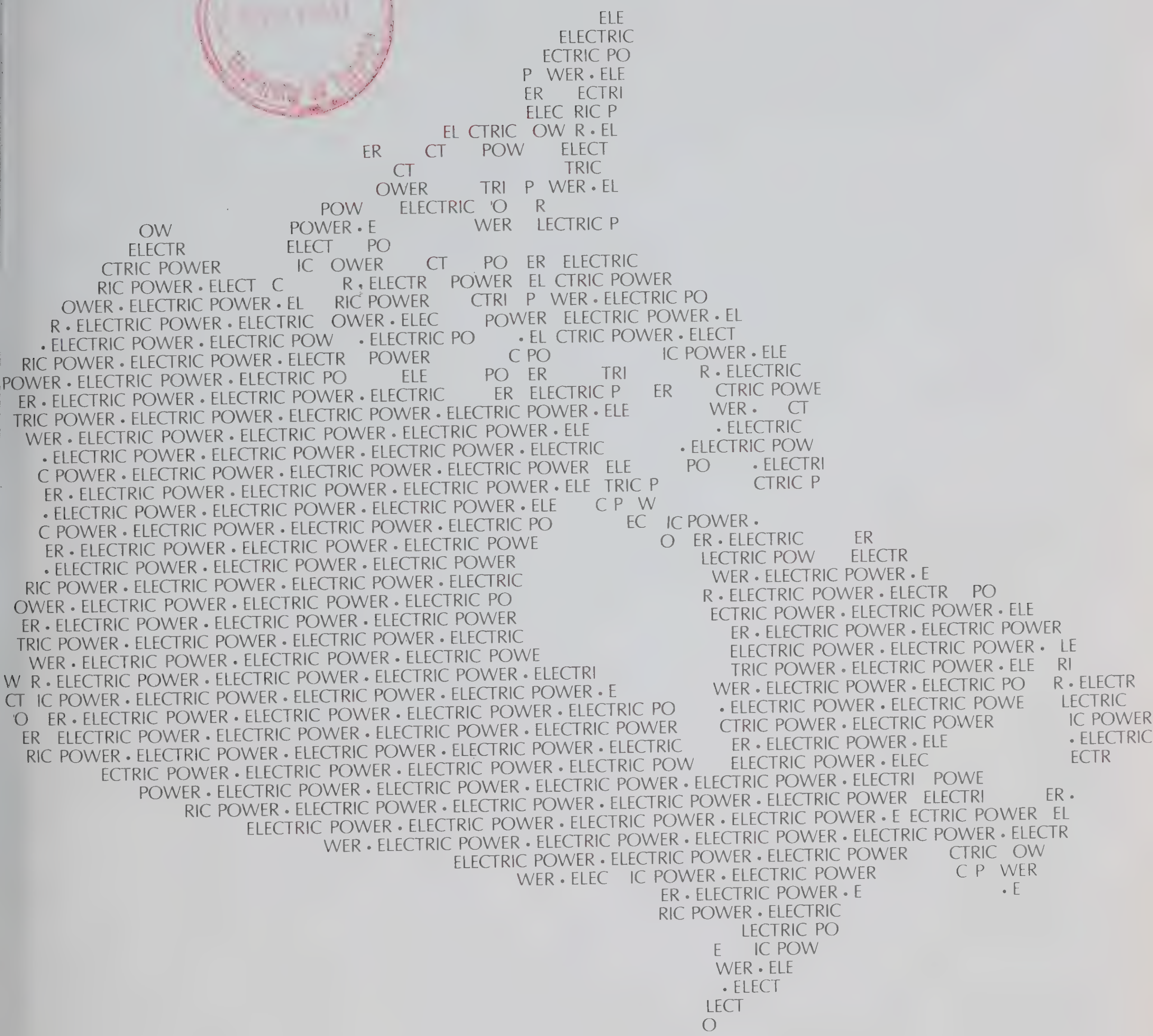
Secondary Energy Consumption:
The amount of energy available to, and used by, the consumer in its final form.

Terawatt Hours (TW.h):
One billion kilowatt hours.

Voltage:
The electrical force or potential that causes a current to flow in a circuit (just as pressure causes water to flow in a pipe). Voltage is measured in volts (V) or kilovolts (kV).
1 kV = 1000 V.

Watt:
The scientific unit of electric power; a rate of doing work at the rate of one joule per second. A typical light bulb is rated 25, 40, 60 or 100 watts, meaning that it consumes that amount of power when illuminated. A horse power is 746 watts.

ELECTRIC POWER IN CANADA 1993



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A Message from the Editor

I am pleased to present the 1993 edition of *Electric Power in Canada* (EPIC), published by the Electricity Branch of Natural Resources Canada. The primary purpose of this publication is to provide a comprehensive review of the Canadian electric power industry.

In order to look at ways of improving EPIC, we undertook our first readership survey in September 1992, the results of which were published in the 1992 issue. For the purpose of continuous quality improvement, we undertook another readership survey in January 1994. We would like to thank those who responded to our request and are pleased to report the key findings of the survey as follows:

- of the 375 readers who responded, 94 per cent indicated that they found the report to be useful;
- 70 per cent said having both the tables and the text was important to them;
- 56 per cent of respondents stated that they use the report primarily for general information or reference; 24 per cent said they use it in the preparation of reports;
- readers found the following four areas of the publication to be of the most interest: (i) Electricity Demand and Supply; (ii) Electricity Outlook; (iii) Electricity Costing and Pricing; and (iv) Electricity and the Environment;
- several respondents pointed out the need to receive the publication earlier;
- others noted the need to make an electronic version available.

In response to your comments, we have made a number of changes to this year's edition of EPIC:

- New sections have been added on the comparison of electricity intensities by province and on the labour productivity of Canada's electric utilities (Chapter 5), as well, a new section on independent power producers in Canada (Chapter 14) has been added;

- Responding to your request for electronic access, a bulletin board service (BBS) is now available. You can access the BBS to obtain the entire publication or any of its parts. The information is available in ASCII format as well as in other formats. However, you cannot read the information on line, it must be downloaded (see the following page for access download procedures).

- New information will be added to the BBS as soon as it becomes available. A message on the BBS will keep you informed of the most recent updates. For more information on use of the BBS, you may call Mr. Yves Demers at (613) 995-2634.

Finally, we are pleased to bring you the 1993 edition of *Electric Power in Canada* two months earlier than last year. I hope you continue to find this publication useful. If you have any additional comments or suggestions, I would be pleased to hear from you.

Po-Chih Lee

Po-Chih Lee, Ph.D.
Editor

Electric Power in Canada (EPIC) Files: Download Procedures

The following explains how to access information from Natural Resources Canada' s (NRCan) Internet/Bulletin Board Service (BBS) server. If you need to know how to use Telnet/Host Presenter or a Modem, ask your computer support person for assistance. Please note that your Mouse will not work with this application. (If you used your mouse, press **Tab** to cancel.) Also, the response to your key strokes may take few seconds. Please, be patient.

<u>If using Internet</u>, use Telnet or any Unix Host Presenter.

- Open a session with Host Name **ES1.ES.EMR.CA** and Session Name **General Unix Profile**

<u>If using a Modem</u>, set your communication software to: **7,N,1,CR,Full** and dial **(613) 996-2741**

<u>Once connected via Internet or a Modem, follow these steps</u>:

- Login as user **energy** (lower case) and follow the instructions. Use **tt** as terminal type.
- For first time users: after typing in your new password, press **Tab** and type new password again, <u>**then**</u> press **Enter**.
- From the NRCan list, highlight "**Electricity**" and press **Enter**.
- Press **F1** at any time to get help on how to navigate/use the BBS.
- From the **Electricity** list, highlight the topic(s) you are interested in and press **Enter** until desired entry list is reached. Highlight which entry you'd like to download and press **Enter**.
- Highlight **d_load** from top menu and press **Enter**.

<u>If using Internet</u>:

- From the **"To"** field, highlight **"ftp";** from the **"Format"** field, highlight **"attachment";** and <u>**then**</u> press **Enter**.
- If there is more than one file attached to the entry, you'll be prompted to confirm each file to be downloaded.
- Enter the appropriate information for the first three fields and press **Enter**. (If you need assistance, ask your computer support person.)
- Download as many files as required.
- If you're already working on a Unix station the file(s) will be in your personal directory. Otherwise, use an **FTP** application (**not** the ftp option within Telnet) to transfer the file(s) onto your personal computer.
- Once the operation is completed, exit NRCan's BBS by pressing **Ctrl-X** twice, selecting "**Quit**", and pressing **Enter**.

<u>If using Modem</u>:

- From the "**To**" field, highlight the transfer protocol used by your communication software; from the "**Format**" field, highlight "**attachment**" and press "**Enter**".
- If there is more than one file attached to the entry, you'll be prompted to confirm each file to be downloaded. Download as many files as required.
- The file(s) will be in your communication software download default directory.
- Once operation is completed, exit NRCan's BBS by pressing **Esc**ape twice, selecting "**Quit**" and pressing **"Enter".**

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Highlights of 1993 Electrical Developments

Electricity Demand

Electricity demand rose only 1.5 per cent in 1993 because of slow growth in the economy. The real Gross Domestic Product grew 2.2 per cent in 1993, recovering from the economic recession of 1990. Energy conservation was the other factor contributing to the small increase in domestic electricity demand. A comparison of electricity demand by province is summarized as follows:

Electricity Demand in Canada (GWh)

Province	1992	1993	% Change
Newfoundland	10 696	10 904	1.9
Prince Edward Island	772	806	4.4
Nova Scotia	9 908	9 919	0.1
New Brunswick	13 883	13 873	-0.1
Quebec	164 605	170 153	3.4
Ontario	139 383	137 483	-1.4
Manitoba	18 376	18 642	1.4
Saskatchewan	14 590	15 279	4.9
Alberta	45 906	46 960	2.3
British Columbia	57 270	58 672	2.3
Yukon	480	335	-30.2
Northwest Territories	581	584	0.5
Canada	**476 450**	**483 610**	**1.5**

Electricity Generation

Electricity generation increased by 1.9 per cent in 1993, much greater than the 1.5 per cent increase for domestic electricity demand. The increase is mainly attributed to a larger number of exports to the United States. Of the total electricity generated in 1993, hydroelectric generation accounted for 62 per cent, nuclear 17 per cent, coal 15 per cent, oil, natural gas, and other 2 per cent each. Electrical energy production by fuel type and by province in 1993 was as follows:

Electrical Energy Production by Fuel Type and by Province in 1993 (GWh)

Province	Coal	Oil	Gas	Nuclear	Hydro	Other	Total
Nfld.	0	1 649	0	0	39 197	0	40 846
P.E.I.	0	59	0	0	0	0	59
N.S.	6 345	2 337	0	0	879	153	9 714
N.B.	1 291	5 232	0	5 323	3 024	242	15 112
Que.	0	244	25	4 807	149 367	0	154 443
Ont.	18 015	2	3 337	78 484	40 290	580	140 708
Man.	185	12	20	0	26 863	41	27 121
Sask.	10 354	43	679	0	4 057	170	15 303
Alta.	39 351	0	5 809	0	1 829	1 288	48 277
B.C.	0	1 191	2 582	0	53 121	1 692	58 586
Yukon	0	48	0	0	287	0	335
NWT	0	237	95	0	252	0	584
Canada	**75 541**	**11 054**	**12 547**	**88 614**	**319 166**	**4 166**	**511 088**

Capacity Additions

Because of the anticipated slow growth of the economy, there were only a few capacity additions. A total of 3284 MW was added in 1993. Of this total, 1870 MW was nuclear, 733 MW hydro, 443 MW coal, 204 MW oil, and 34 MW natural gas. By the end of 1993, total installed generating capacity by fuel type and by province was as follows:

Installed Generating Capacity by Fuel Type and by Province in 1993 (MW)

Province	Coal	Oil	Gas	Nuclear	Hydro	Other	Total
Nfld.	0	792	0	0	6 650	5	7 447
P.E.I	0	121	0	0	0	0	121
N.S.	1 383	539	0	0	390	18	2 330
N.B.	703	2 106	0	680	902	87	4 478
Que.	0	1 440	85	685	30 065	5	32 280
Ont.	10 628	2 554	909	14 492	7 209	159	35 951
Man.	369	16	4	0	4 498	23	4 910
Sask.	1 466	22	432	0	836	22	2 778
Alta.	5 581	18	1 807	0	823	152	8 381
B.C.	0	242	975	0	11 223	526	12 966
Yukon	0	57	0	0	77	0	134
NWT	0	140	19	0	49	0	208
Canada	**20 130**	**8 052**	**4 231**	**15 857**	**62 722**	**992**	**111 984**

Electricity Exports to the United States

In 1993, electricity exports to the United States increased 17 per cent over 1992, reaching 29 364 GWh, while imports from the United States increased 47 per cent to 2692 GWh. Exports accounted for 5.8 per cent of Canada's total electricity generation in 1993, up from 5.2 per cent in 1992. Export revenue also increased significantly by 21 per cent, from $708 million in 1992 to $858 million in 1993, while import costs increased slightly from $84 million in 1992 to $85 million in 1993.

Export increases in 1993 occurred mainly in Ontario, Quebec, and Manitoba due to improved water flows in these provinces. An increase in demand for electricity in New York and New England also contributed to the increase in exports.

Capital Investment

Electric utilities spent $9.6 billion on facilities in 1993, accounting for 48 per cent of the total investment in the energy sector and 8 per cent of the total investment in the economy. Of the total, about 51 per cent was for generation, 22 per cent for distribution, 16 per cent for transmission, and 11 per cent for other. As of December 31, 1993, the total outstanding long-term debt of the 15 major electric utilities in Canada was $88 billion. Of this total, about 64 per cent ($56 billion) was borrowed on the domestic market, and 36 per cent ($32 billion) was raised on international markets.

Rate Increases

In 1993, Ontario Hydro had the largest rate increase at 7.9 per cent, followed by Yukon Energy Corporation at 6.8 per cent and Alberta Power at 5.1 per cent. A weighted average for Canada was about 3.7 per cent. This increase was much higher than the Consumer Price Index, which registered an increase of only 1.8 per cent.

Demand-Side Management

It is estimated that about 780 MW of generating capacity and 6110 GWh of energy were saved due to the implementation of demand-side management (DSM) by electric utilities in 1993. Cumulative generating capacity savings as of December 31, 1993, were about 5055 MW.

Non-Utility Generation

For non-utility generators (NUG), it is estimated that about 619 MW of generating capacity, mainly cogeneration, was added in 1993, and they sold about 6053 GWh of energy to the major electric utilities.

Chapter 1

The Electric Power Industry in Canada

Industry Structure

The modern electric utility industry began in the 1880's. It evolved from gas and electric carbon-arc commercial and street lighting systems. Thomas Edison's Pearl Street electricity generating station, which opened on September 4, 1882, in New York City, was the first to introduce the modern electric utility system to the world.

Today electricity is vital to almost every aspect of the Canadian economy and is projected to continue to expand its role over the next ten years. From 1947 to the end of 1993, net electricity generation increased at an annual average rate of 5.3 per cent, compared with real Gross Domestic Product of 4.1 per cent, and total population growth of 1.8 per cent. Canada's electric power industry is made up of provincial Crown corporations, investor-owned utilities, municipal utilities and industrial establishments. The federal role regarding electricity is restricted to nuclear energy and international and interprovincial trade.

Under the Canadian constitution, electricity is primarily within the jurisdiction of the provinces. As a result, Canada's electrical industry is organized along provincial lines. In most provinces the industry is highly integrated, with the bulk of the generation, transmission and distribution provided by a few dominant utilities. Although some of these utilities are privately owned, most are Crown corporations owned by the provinces. The dominant utilities are listed in Table 1.1 and who does what in the electric power industry is summarized in Table 1.2.

Among the major electric utilities, seven are provincially owned, five are investor owned, two are municipally owned, and two are territorial Crown corporations. In 1993, provincial electric utilities owned about 82 per cent of Canada's total installed generating capacity and produced about 79 per cent of total generated electricity. The five investor-owned utilities accounted for 9 per cent of all Canadian electric utility capacity and produced about 8.6 per cent of total electricity. Municipally owned utilities accounted for 1.3 per cent of capacity ownership, and produced 1.5 per cent of total generated electricity. The two territorial Crown corporations accounted for 0.3 per cent and 0.2 per cent of capacity and generation respectively.

In addition to the 16 major electric utilities, there are about 60 industrial establishments generating electricity mainly for their own use. A few also sell energy to municipal distribution systems or utilities. These industries are concentrated in the pulp and paper, mining and aluminum smelting sectors. In 1993, industrial establishments owned about 5.7 per cent of total capacity and produced about 8.2 per cent of total generated electricity in Canada, as shown in Table 1.3.

As well as the major electric utilities and industrial establishments, there are about 364 smaller utilities across Canada, of which 87 per cent are located in Ontario. Most of these small utilities are owned by municipalities. They do not own generating capacity; instead, they usually purchase power from the major utility in their province. Several small investor-owned utilities, however, have their own generating capacity. In 1993, small utilities accounted for 1.3 per cent of total Canadian capacity and produced 1.5 per cent of electrical energy.

During the past few years, some independent power producers (IPP) have also been established across Canada, dedicating their entire electricity generation for sales to major electric utilities. These IPP normally do not have their own service areas. In 1993, IPP owned about 0.9 per cent of Canada's total

installed capacity and produced 1.5 per cent of total generated electricity.

Electricity and the Economy

The electric power industry has a significant presence within the Canadian economy. As indicated in Table 1.4, there were almost 94 000 people directly employed by the industry in 1993, (about 0.8 per cent of total Canadian employment), down 2.0 per cent from 1992, reflecting the continuous restructuring of Canada's electric power industry in 1993. Total revenue increased to about $26 billion in 1993. Of this total, approximately $858 million or 3.3 per cent came from export earnings. The electric power industry has steadily increased its contribution to Canada's Gross Domestic Product, from 2.3 per cent in 1960, to 2.5 per cent in 1970, to 3.0 per cent in 1980, to 3.3 per cent in 1991, to 3.7 per cent in 1993.

The electric power industry had the largest investment share in the energy sector in 1993, with total capital expenditures of $9.6 billion accounting for about 47 per cent of the total investment in the energy sector, and 8 per cent of the total investment in the economy. Total assets of the industry were about $140 billion in 1993, accounting for about 7.5 per cent of the capital stock of the economy, excluding the residential sector. This reflects the capital-intensive nature of the electric power industry. Hydro-Québec, Ontario Hydro and B.C. Hydro were the three largest electric utilities in Canada and, in terms of assets, ranked second, third, and eleventh respectively among all Canadian companies.

Canadian Electric Utilities

Newfoundland

In Newfoundland, the generation and distribution of electricity is dominated by two utilities, Newfoundland Light & Power Company Limited (NLPC) and Newfoundland and Labrador Hydro (NLH). Together, NLPC and NLH serve about 236 000 customers.

NLPC, an investor-owned utility, is the primary retailer of electricity on the island. NLPC was incorporated in 1966 through the amalgamation of St. John's Electric Light Company Limited, United Towns Electric Company Limited and Union Electric Light and Power Company. Approximately 92 per cent of the company's power supply is purchased from NLH, with the balance generated by its own hydro stations. NLPC is a subsidiary of FORTIS Inc., formed in 1987, which owns and operates subsidiaries that include NLPC, a residential mortgage company, and a property investment company.

NLH is a provincial Crown corporation, whose mandate is to generate and transmit electricity in the province. It was established by an act of the provincial legislature in 1954 and was incorporated in 1975. It is the parent company of a group that includes Churchill Falls (Labrador) Corporation (CFLCo), the Lower Churchill Development Corporation (LCDC), Twin Falls Power Corporation Limited, Gull Island Power Co. Ltd., and the Power Distribution District of Newfoundland and Labrador. NLH has 51 per cent ownership in LCDC; the Government of Canada owns the remaining 49 per cent. Through CFLCo, NLH owns and operates the Churchill Falls plant, one of the largest power facilities in the world. NLH's on-island capacity is generated from oil and hydro sources.

Prince Edward Island

Maritime Electric Company Limited (MECL) is an investor-owned utility that has provided electricity service to Prince Edward Island since 1918. The company owns and operates a fully integrated electric utility system providing for the generation, transmission and distribution of electricity throughout the island. MECL operates two oil-fired generating plants on the island, and has a 10 per cent equity interest in New Brunswick Electric Power Commission's coal/oil-fired No. 2 unit located in Dalhousie, N.B. Two submarine cables link MECL's system with New Brunswick's power grid. MECL is the major distributor on the island, serving about 52 800 customers. A municipal utility in the town of Summerside has its own distribution system and purchases power from MECL.

Nova Scotia

The Nova Scotia Power Corporation (NSPC) was incorporated in 1973. Prior to 1992, it was a provincial Crown corporation producing and distributing electricity throughout the province. However, on January 9, 1992, the Nova Scotia government announced the privatization of this utility in order to release provincial taxpayers from the financial burden associated with NSPC's $2.4 billion debt. An Act respecting the privatization of NSPC was introduced in the provincial Legislature on April 16, 1992, and passed on June 19, 1992. Nova Scotia Power Corporation commenced operation as an investor-owned utility on August 13, 1992. NSPC generates most of its electricity from thermal energy, with more than 68 per cent of the production coming from coal. The utility also maintains hydro-generation and oil-fired facilities, and purchases power from New Brunswick. The largest portion of the province's total production is derived from the Lingan generating station located on Cape Breton Island. In 1993, NSPC served about 410 000 customers.

New Brunswick

The New Brunswick Electric Power Commission (NB Power) was established by an act of the New Brunswick Legislature in 1920. The mandate of NB Power is to generate and distribute power under public ownership to all areas of the province. The utility owns and operates 15 generating stations, and electricity is generated from a balance of nuclear, hydro and thermal sources. NB Power also purchases energy from Quebec. In 1993, NB Power directly provided electricity to 325 000 customers and indirectly served an additional 40 000 customers through sales to two municipal utilities.

Quebec

Hydro-Québec is a Crown corporation, established by the provincial Legislative Assembly in April 1944. It is responsible for the generation, transmission and distribution of most of the electricity sold in Quebec, and also sells and purchases both power and energy under agreement with neighbouring electrical systems in Canada and the United States. Almost all of the electricity generated by Hydro-Québec at its stations throughout the province is from hydraulic sources. The utility currently serves about 3.3 million customers, and ranks among North America's largest electric utilities in terms of assets and volume of sales.

Hydro-Québec has six wholly owned subsidiaries: the Société d'énergie de la Baie James, which carried out the construction of Phase 1 of La Grande complex and which now manages large construction projects for Hydro-Québec; Hydro-Québec International, which provides engineering and consulting services abroad for electric power projects; Cedars Rapids Transmission Company Limited, which owns and operates a transmission line between Quebec and New York State; Somarex Inc., which was created to finance, construct

and operate a transmission line in the State of Maine; Nouveler Inc., which promotes energy efficiency and alternative energy sources; and Société 2312-0843 Quebec Inc., which is a partner in the limited partnership société en commandite HydrogenAL II and which, on January 1, 1990, became a partner in the limited partnerships société en commandite HydrogenAL and société en commandite ArgonAL, whose other partner is Canadian Liquid Air Ltd.

Hydro-Québec has a 34.2 per cent interest in Churchill Falls (Labrador) Corporation Limited, which operates the Churchill Falls power plant. Under the contract, Hydro-Québec buys the bulk of the Labrador station's 5,429 MW output at an average price of 0.3 cents/kWh. It also has a 50 per cent interest in HydrogenAL Inc., HydrogenAL II Inc., and ArgonAL Inc.

By the end of 1993, Hydro-Québec had a total of 84 generating stations: 54 hydroelectric, 29 conventional thermal, and one nuclear.

Ontario

Ontario Hydro is a provincially owned corporation, established in 1906 by a special statute of the Province of Ontario. Ontario Hydro is a financially self-sustaining corporation without share capital. Bonds and notes issued to the public are guaranteed by the Province. Under the Power Corporation Act, the main responsibility of Ontario Hydro is to generate, supply and deliver electricity throughout Ontario. It also produces and sells steam and hot water as primary products. Working with municipal utilities and with the Canadian Standards Association, Ontario Hydro is responsible for the inspection and approval of electrical equipment and wiring throughout the province.

Ontario Hydro sells wholesale electric power to 309 municipal utilities, which in turn retail it to customers in their service areas. Ontario Hydro also directly serves about 104 large industrial customers and more than 945 000 small business and residential customers in rural and remote areas. In 1993, more than 3.7 million customers were served by Ontario Hydro and the municipal utilities in the province. Ontario Hydro operates 82 power stations: 69 hydroelectric, 8 conventional thermal, and 5 nuclear. Ontario Hydro also operates an extensive transmission system of about 135 000 km across the province.

The year 1992 marked the beginning of a new era for Ontario Hydro. A number of factors combined to confront the corporation with perhaps the most serious crisis in its 87-year history. Two compelling requirements were brought into focus: one was a need to reduce costs in order to halt spiralling rate increases and to control and reduce the company's indebtedness; and the other was a need to re-structure the corporation to make it more efficient and more competitive.

In Ontario, there are also a number of small regional utilities. An example is Great Lakes Power Limited, a private hydroelectric generation and distribution utility operating in Sault Ste. Marie and west of the Algoma district of Ontario. In 1993, the utility served over 10 000 customers in northern Ontario directly, and another 30 000 indirectly.

Manitoba

The Manitoba Hydro-Electric Board (Manitoba Hydro) is a Crown corporation established in 1949 by the provincial legislature. It has broad powers to provide electric power throughout the province and operates under the 1970 Manitoba Hydro Act. Almost all of the province's electric power is produced by Manitoba Hydro at its generating stations on the Churchill/Nelson river system in northern Manitoba. Manitoba Hydro distributes electricity to consumers throughout the province, except for the central portion of

Winnipeg, which is served by the municipally owned Winnipeg Hydro. Manitoba Hydro and Winnipeg Hydro operate as an integrated electrical generation and transmission system. In 1993, Manitoba Hydro served more than 382 000 customers directly, and Winnipeg Hydro served over 91 000 customers.

Manitoba Hydro produces electricity by operating 12 hydroelectric generating stations, two thermal generating stations, and 13 diesel sites. Limestone Hydro Project (10x133 MW) was completed in 1992, ahead of schedule and under budget.

Saskatchewan

The Saskatchewan Power Corporation (SaskPower) is a Crown corporation operating under the 1950 Power Corporation Act. Under the Act, the mandate of SaskPower includes the generation, transmission and distribution of electricity. At the end of 1993, the corporation served more than 407 000 customers with electricity. The bulk of the electricity generated by SaskPower is from thermal sources. In 1993, coal-fired stations produced about 69 per cent of total electricity, followed by hydro at 27 per cent, and natural gas at 4 per cent.

The Shand Power Station (1x300 MW) was completed and began producing electricity in 1992. Shand is one of Canada's most environmentally advanced coal-fired stations.

In 1988, the gas operations of the corporation became separate companies within SaskPower. The parent company of the gas operations is the Saskatchewan Energy Corporation (SaskEnergy). In 1989, SaskEnergy became a totally separate company.

Alberta

There are three major electric utilities in Alberta: TransAlta Utilities Corporation, Alberta Power Limited, and Edmonton Power. Together, they supply about 93 per cent of Alberta's electrical energy requirements. All are linked by a transmission network largely owned by TransAlta. The remaining 7 per cent of Alberta's electrical energy is supplied by industry. Over 88 per cent of the electricity generated by Alberta utilities is produced by large coal-fired generating stations.

TransAlta Utilities Corporation, formerly Calgary Power Limited, is the largest investor-owned electric utility in Canada. The company was incorporated under the laws of Canada and has been engaged in the production and distribution of electricity in the Province of Alberta since 1911. About 61 per cent of the electric energy requirements of Alberta are supplied by TransAlta, to over half of the population. In 1993, more than 327 000 customers were served directly by TransAlta, while another 315 000 customers were served indirectly through wholesale contracts. TransAlta has a number of subsidiaries: TransAlta Resources Corporation, its principal subsidiary, holds investment in non-regulated activities including TransAlta Technologies Inc.; TransAlta Energy Systems Corporation which provides building automation and energy management services across Canada; TransAlta Fly Ash Ltd.; Kanelk Transmission Company Limited; and Farm Electric Services Ltd.

Alberta Power Limited, incorporated in 1972, is another investor-owned electric utility in Alberta, and a subsidiary of Canadian Utilities Limited. The activity of the company is concentrated in east-central and northern Alberta. In 1993, Alberta Power supplied about 18 per cent of total Alberta electricity requirements and served about 149 000 customers.

Edmonton Power has the largest generating capacity of any municipally owned utility in Canada. Since its creation in 1902, Edmonton Power has kept pace with the growth and

development of Edmonton. In 1993, the utility produced about 14 per cent of Alberta's electricity requirements and served more than 251 000 customers. Edmonton Power purchased about 2 per cent of its electricity requirements from TransAlta Utilities and Alberta Power.

In 1992, Edmonton City Council created the Edmonton Power Authority which went into effect on January 1, 1993. The status as an Authority was an interim step in incorporating Edmonton Power as a wholly-owned subsidiary of the city rather than a department of the city. It was felt that Edmonton Power would best serve its customers by operating under subsidiary status.

British Columbia

British Columbia Hydro & Power Authority (B.C. Hydro) was incorporated in 1962 and is a Crown corporation operating in British Columbia. B.C. Hydro provides electrical service throughout the province, with the exception of the southern interior which is served by West Kootenay Power and Light Company, Limited. B.C. Hydro is the third largest electric utility in Canada. It generates, transmits and distributes electricity to more than 1.3 million customers in a service area which contains more than 92 per cent of the population of the province.

In 1988, B.C. Hydro proceeded with a corporate restructuring that resulted in the privatization of its mainland gas operations and its rail operations, and the creation of a number of subsidiaries. B.C. Hydro International Limited provides consulting services in the areas of engineering and utility operations to Canadian and international customers. British Columbia Power Export Corporation (POWEREX) was established to market the province's firm electricity exports. POWEREX negotiates and administers firm export sales agreements with U.S. utilities and purchase agreements with electricity producers, and will make arrangements with Hydro for services such as transmission facilities. Powertech Labs Inc. was formed to provide research, testing and consulting work for electrical technological development. Westech Information Systems Inc. was created in 1989 to offer a wide range of professional services, including the design, development and maintenance of integrated computer systems. Western Integrated Technologies Inc. was also created in 1989 to provide technical support and data processing operations.

West Kootenay Power is an investor-owned utility supplying electric service in the southern interior of British Columbia. The company generates and distributes hydroelectricity directly to more than 74 000 customers in its service area. It also supplies power to seven wholesale customers, who in turn serve almost 38 000 customers. West Kootenay Power is owned by UtiliCorp United Inc. of Kansas City, Missouri.

Yukon

Two utilities provide electrical service to about 12 000 customers in the Yukon. The largest of these, in terms of revenues and generating capacity, is the Yukon Energy Corporation. It is a territorial Crown corporation that has taken over responsibility for the Yukon assets of the Northern Canada Power Commission (NCPC). The Yukon Development Corporation (the parent corporation of the Yukon Energy Corporation) has entered into a five-year management services agreement with the Yukon Electrical Company Limited (YECL). Under the terms of the agreement, YECL will operate the Yukon Energy Corporation's assets, purchase the electricity generated, and distribute it to the Energy Corporation's customers. The Energy Corporation's customers include all of

the Yukon's major industries and 13 per cent of the Yukon's non-industrial customers.

In addition to its responsibilities to the Yukon Energy Corporation, YECL (a subsidiary of Canadian Utilities Limited) also generates and distributes power to its own customers. YECL serves 18 communities in the Yukon, including Whitehorse. It purchases the majority of its electrical requirements from the Yukon Energy Corporation.

Northwest Territories

Electrical service to about 14 000 customers in the Northwest Territories is provided by the Northwest Territories Power Corporation (NWTPC) and Northland Utilities Enterprises Limited (Northland). The largest of these, in terms of revenues and generating capacity, is the NWTPC. It is a territorial Crown corporation, which in 1988 took over responsibility for the Northwest Territories' assets of the NCPC. NWTPC provides electrical service to 51 communities in the N.W.T. and wholesales hydro-power to Northland.

Northland is an investor-owned utility and is a subsidiary of Canadian Utilities Limited. It provides electrical service to seven communities in the south-western region of the N.W.T.

Tables referred to in this chapter are on the following pages.

Tables & Figures

Table 1.1
Canada's Major Electric Utilities by Province

Province	Electric Utility	Ownership
Newfoundland	Newfoundland and Labrador Hydro	Provincial
	Newfoundland Light & Power Company Limited	Private
Prince Edward Island	Maritime Electric Company Limited	Private
Nova Scotia	Nova Scotia Power Incorporated	Private
New Brunswick	New Brunswick Electric Power Commission	Provincial
Quebec	Hydro-Québec	Provincial
Ontario	Ontario Hydro	Provincial
Manitoba	The Manitoba Hydro-Electric Board	Provincial
	City of Winnipeg Hydro-Electric System	Municipal
Saskatchewan	Saskatchewan Power Corporation	Provincial
Alberta	Alberta Power Limited	Private
	Edmonton Power	Municipal
	TransAlta Utilities Corporation	Private
British Columbia	British Columbia Hydro & Power Authority	Provincial
Yukon	Yukon Energy Corporation	Territorial
Northwest Territories	Northwest Territories Power Corporation	Territorial

Source: Natural Resources Canada

Table 1.2
Electricity in Canada - Who Does What

Function	Provinces	Canada
R&D	Utilities, Canadian Electrical Association	Atomic Energy of Canada Limited (AECL)
Planning	Utilities Governments	
Generation Design	Utilities	Atomic Energy of Canada Limited (AECL)
Generation Operation	Utilities	
Transmission	Utilities	
Distribution	Utilities	
Project Regulation	Regulatory Board or Equivalent	Atomic Energy Control Board (AECB)
Rate Regulation	Regulatory Board or Equivalent	
Export Regulation		National Energy Board
Interprovincial Trade Regulation	Utilities (unwritten rules)	National Energy Board (authority limited)
Environmental Regulation	Provincial Mechanisms	Federal Environmental Assessment Review Office (FEARO)

Source: Natural Resources Canada

Table 1.3
Electrical Capacity and Production by Utilities and Industrial Establishments, 1930-93

	Installed Generating Capacity			Energy Production		
Year	Utilities (%)	Industrial Establishments (%)	Capacity (MW)	Utilities (%)	Industrial Establishments (%)	Generation (GWh)
1930	83	17	5 573	93	7	19 468
1940	84	16	8 104	91	9	33 062
1950	83	17	11 076	88	12	55 037
1960	80	20	23 035	78	22	114 378
1965	82	18	29 348	77	23	144 274
1970	88	12	42 826	84	16	204 723
1975	90	10	61 352	87	13	273 392
1980	92	8	81 999	89	11	367 306
1985	93	7	97 020	92	8	447 182
1988	94	6	101 055	92	8	490 672
1989	94	6	101 960	92	8	482 152
1990	94	6	102 947	91	9	465 744
1991	94	6	105 424	92	8	493 026
1992	94	6	108 700	92	8	501 631
1993	94	6	111 984	92	8	511 088

Source: Electric Power Statistics, Volume II, Statistics Canada, 57-202, 57-001

Table 1.4
Electric Utility Assets, Revenue and Employees, 1993

Utility	Assets ($ millions)	Revenue ($ millions)	Employees (persons)
Major Utilities:			
Newfoundland and Labrador Hydro	2 067	373	1 495
Newfoundland Light & Power Co. Ltd.	480	346	810
Maritime Electric Co. Ltd.	135	81	234
Nova Scotia Power Corporation*	2 679	738	2 213
New Brunswick Electric Power Commission*	4 129	903	3 027
Hydro-Québec	47 879	7 036	26 781
Ontario Hydro	44 706	8 363	24 971
The Manitoba Hydro-Electric Board*	5 455	823	4 200
City of Winnipeg Hydro-Electric System	131	116	607
Saskatchewan Power Corporation	3 201	790	2 300
TransAlta Utilities	4 251	1 388	2 736
Edmonton Power	2 044	411	1 150
Alberta Power Limited	1 900	550	1 470
B.C. Hydro and Power Authority*	10 005	2 178	6 318
Yukon Energy Corporation*	129	15	100
Northwest Territories Power Corporation*	278	99	300
Other Utilities	11 000	1 800	15 000
Canada	140 269	26 060	93 712

*As at March 31, 1993

Source: Electric utilities' annual reports

Canadian Electricity in the International Context

World Primary Energy Consumption

This chapter compares Canada's electricity supply, demand, trade, intensity and pricing with those of selected other countries in the world. The data used in this chapter were obtained from reputable sources such as the United Nations' Energy Statistics Yearbook and the International Energy Annual published by the Energy Information Administration of the U.S. Department of Energy. Data on the comparison of electricity prices by sector was taken from an annual survey produced by the Electricity Branch of Canada's Department of Natural Resources.

During the past 10 years, the world's total primary energy consumption (petroleum, natural gas, coal, hydroelectricity and nuclear electricity) has increased steadily at an average annual rate of 2.2 per cent. However, individual primary energy forms grew at different rates: petroleum, coal and hydroelectricity increased at a rate below average, while natural gas and nuclear rose substantially above average.

World consumption of petroleum increased from 58.7 million barrels (about 359 petajoules) per day in 1983 to 66.7 million barrels per day in 1992, with an average annual growth rate of only 1.4 per cent. Petroleum is still the largest component of the world's total primary energy consumption, accounting for about 40 per cent. The slow growth of petroleum demand is mainly attributed to a depressed world economy in general, fuel substitution and conservation efforts.

World consumption of dry natural gas rose from 54.4 trillion cubic feet (about 57 392 petajoules or 1.5 trillion cubic metres) in 1983 to 74.7 trillion cubic feet (2.1 trillion cubic metres) in 1992, an average annual growth rate of 3.6 per cent. The use of natural gas for space heating and power generation has been popular in recent years because of its competitive price and reduced environmental impact.

World consumption of coal rose from 4.4 billion short tons (about 118 000 petajoules) in 1983 to 5.0 billion short tons in 1992 with an average annual growth rate of 1.6 per cent. The four largest consumers in 1992 were: China at 1.20 billion, the United States at 0.89 billion, Russia[1] at 0.38 billion, and Germany at 0.36 million short tons. Because of its emissions problem, the growth of coal demand is expected to remain slow.

World consumption of hydroelectric power increased from 1910 TWh (about 6 875 petajoules) in 1983 to 2204 TWh in 1992, with an average annual growth rate of 1.6 per cent. As most of the economical hydro sites have been developed in the world, an increase of hydroelectricity demand is expected to be slow. Canada, the United States, Brazil and Russia were the four largest hydroelectricity consumers in the world in 1992.

World consumption of nuclear energy has grown the fastest during the past 10 years, rising from 982 TWh in 1983 to 2017 TWh in 1992, with an average annual growth rate of 8.3 per cent, about four times larger than that of the world's total primary energy consumption.

In the primary energy consumption, a great portion of coal consumption is used for baseload electricity generation. The same is true for petroleum and natural gas consumption. However, petroleum is mainly used for peak demand, while natural gas is used for both peak demand and baseload. Because of the difficulty of estimating the portions of petroleum, coal and natural gas used for electricity generation at the world level, it is hard to present the world's total

[1] The former Soviet Union ceased to exist on December 25, 1991.

primary energy consumption delivered in the form of electricity.

Based on the U.S. Department of Energy's estimate, world total net electricity consumption (excluding transmission and distribution losses) rose from 7996 TWh in 1983 to 10 797 TWh in 1992, an average annual growth rate of 3.4 per cent, much greater than the world's total primary energy consumption of 2.2 per cent registered during the same period 1983-92.

Canada holds a significant place in the world's electric power industry. Canada is not only a world leader in long-distance electric power transmission, but also the largest hydroelectric power producer, an important consumer and a big exporter.

Installed Generating Capacity

During the past 20 years, the growth of Canada's electric power industry has kept in line with the world's electric power industry as a whole. World installed generating capacity rose from 1113 GW in 1970 to 2847 GW in 1991, with an average annual growth rate of 4.6 per cent. While Canada's system increased from 43 GW to 105 GW, with an average annual growth rate of 4.4 per cent during the same period 1970-1991. The main difference between these two systems is that Canada's system is predominately hydro, accounting for 57 per cent of total installed capacity in 1991, and total world generating capacity is predominately conventional thermal, accounting for 65 per cent of the total.

Table 2.1 reports the 20 largest electrical systems in the world, and the world total for all 190 countries and areas. Of this world total, conventional thermal (consisting of installed capacity from coal, oil and natural gas) accounted for 1842 GW (64.7 per cent); hydro 653 GW (22.9 per cent); nuclear 343 GW (12.1 per cent); and geothermal only 9 GW (0.3 per cent).

In 1991, North America had 33 per cent of the world's total installed generating capacity, the same as in 1990, followed by Europe at 24 per cent, dropping one percentage point from 1990, Asia at 22 per cent, up by one percentage point from 1990, the Soviet Union at 12 per cent, South America at 4 per cent, Africa at 3 per cent and Oceania at 2 per cent.

The U.S. electric power industry was the largest in the world, with a total installed capacity of 788 GW, accounting for 28 per cent of the world total. The Soviet Union was second, with an installed capacity of 344 GW, and Japan was third with 200 GW. The United States led in installed capacity for every fuel type: U.S. conventional thermal accounted for 32 per cent of the world's thermal capacity; hydro for 14 per cent; nuclear for 32 per cent; and geothermal for 56 per cent.

Canada ranked seventh in the world with an installed generating capacity of about 105 GW (behind the United States, Soviet Union, Japan, China, Germany and France), accounting for 4 per cent of the world total. In terms of fuel type, Canada's hydro capacity is the third largest in the world, next to the U.S. and the Soviet Union. Canada's nuclear capacity is sixth in the world, and its conventional thermal capacity is eighth.

Electricity Generation

World electricity generation grew almost at the same rate as generating capacity has during the past 20 years. World electricity generation increased from 4908 TWh in 1970 to 12 034 TWh in 1991, with an average annual growth rate of 4.4 per cent. In terms of fuel type, the average growth rate was 3.6 per cent for thermal, 3.1 per cent for hydro and 16.9 per

cent for nuclear. Canada's electrical system experienced similar growth patterns as did the world as a whole. Canada's total generation rose from 205 TWh in 1970 to 508 TWh in 1991, with an average annual growth rate of 4.4 per cent. By fuel type, thermal grew 4.4 per cent, hydro 3.1 per cent, and nuclear 15.6 per cent for the period 1970-1991. However, hydro was the main source of generation in Canada, accounting for 62 per cent of the Canadian total, as compared with only 17 per cent for the world total.

In 1991, a total of 12 034 TWh of electricity was generated around the world: conventional thermal, mainly from coal-fired stations, accounted for 7681 TWh (63.8 per cent); hydro 2236 TWh (18.6 per cent); nuclear 2078 TWh (17.3 per cent); and geothermal 39 TWh (0.3 per cent). (See Table 2.2.) Although nuclear accounted for only 12.1 per cent of the world's total capacity in 1991, its energy generation share was 17.3 per cent, indicating that most nuclear stations were operating at a relatively high capacity factor compared with conventional thermal stations and hydro plants.

In 1991, production shares of electricity by region were the same as in 1990. North America accounted for 31 per cent of the world's total net electricity generation; Europe had 24 per cent; Asia had 22 per cent; the Soviet Union had 14 per cent; South America had 4 per cent; Africa had 3 per cent and Oceania had 2 per cent.

About 26 per cent of total world electricity generation took place in the United States in 1991. Its conventional thermal generation was 2159 TWh, accounting for 28 per cent of total world conventional thermal. The United States was also the largest nuclear energy producer in the world in 1991, with a total of 613 TWh or 29 per cent of total world nuclear. As a proportion of total national electricity production, however, France's nuclear generation was the largest at about 73 per cent, followed by Belgium at 60 per cent and Sweden at 52 per cent. Canada's nuclear share was a relatively small 17 per cent. The nuclear shares of the United States and the Soviet Union were 20 per cent and 12 per cent respectively.

Canada's total electricity production ranked sixth in the world (behind the U.S., the Soviet Union, Japan, China and Germany), with total production of 508 TWh or 4 per cent of the world total. However, Canada was the largest hydroelectric power producer in the world with total generation of more than 308 TWh, accounting for about 14 per cent of the world's total hydroelectric generation (Table 2.2).

Per Capita Electricity Consumption

World per capita electricity consumption was 2227 kWh in 1991, up 2 per cent from 1990. North America had the highest average of 8796 kWh; followed by Oceania at 7061 kWh; the Soviet Union at 5818 kWh; Europe at 5726 kWh; South America at 1550 kWh; Asia at 849 kWh; and Africa at 482 kWh.

Canada's per capita electricity consumption ranked second in the world in 1991 at 18 134 kWh, next only to Norway's 25 319 kWh. As Table 2.3 shows, per capita consumption varies significantly among countries. Norway consumed more than 10 times the world average; Canada more than seven times; and the United States about five times. Nigeria and India's per capita consumption levels were less than 16 per cent of the world average. Although China was the fourth largest electricity producer in the world, its per capita consumption was only 27 per cent of the world average.

Two principal factors contribute to Canada's large per capita consumption of electricity. Abundant water resources have permitted the development of economical hydroelectric power

projects in various regions, making electrical energy relatively inexpensive and plentiful. This has led to relatively high electricity consumption among all energy users, and it has led many electricity-intensive industries to locate in Canada. As well, Canada's northerly location means a long and cold winter, resulting in much electricity being used for space-heating purposes. Currently, about 34 per cent of total households in Canada use electricity for space heating.

Total Electricity Consumption Growth

World electricity consumption grew by approximately 2.7 per cent annually between 1988 and 1991. Among various regions, Asia had the highest electricity consumption growth rate, at 6.8 per cent for the period 1988-91. It was followed by Oceania at 3.7 per cent, South America at 3.1 per cent, Africa at 2.6 per cent, North America at 2.1 per cent, Europe at 1.7 per cent and the Soviet Union at -0.2 per cent.

As was pointed out earlier, Asia was the only region in the world with an increase in electrical capacity shares in 1991. This increase was mainly attributed to high electricity demand growth, which was the result of relatively high economic growth in the region.

Table 2.4 reports total electricity consumption growth rates during 1988-91, for the 20 largest electricity producers in the world. In general, most of the countries with high consumption growth rates were developing countries. Many of these countries have been engaged in the industrialization of their economies and, as a result, have increased their electrical energy consumption significantly.

Japan and Spain were the few developed countries with a high electricity consumption growth rate for the same period. Surprisingly, Germany and Sweden were among the countries with the lowest consumption growth rates in the world during the past four years.

Electricity Trade

Electricity exchanges among countries can provide a wide variety of benefits to the consumers and electric utilities of trading countries. Interconnections improve the economics and security of electricity supply and they reduce the level of capacity needed to meet peak loads. Interconnections also improve the flexibility of electricity supply, making it possible to minimize costs by replacing the highest-cost generation, such as oil-fired generation, with imported hydroelectric energy.

In 1991, a total of 270 TWh of electricity was exported internationally, accounting for about 2.2 per cent of world production (Table 2.5). These exports took place mainly in North America and Europe, where there are extensive interconnections between electrical generating stations.

Europe, the Soviet Union and North America accounted for 96 per cent of total world electricity exports in 1991. As shown in Table 2.5, France was the largest electricity exporter in the world in 1991, with a total of more than 59 TWh, accounting for about 22 per cent of total world exports and 13 per cent of its own total production. Germany was second, accounting for 10 per cent and Canada was third with 9 per cent of total world exports. Canada exported 25 TWh of electricity to the United States in 1991, an increase from sixth place in 1990.

On the import side, the world total was 272 TWh, accounting for 2.3 per cent of total world consumption in 1991 (Table 2.6). Again, Europe and North America were the major

trading areas, accounting for 89 per cent of total world imports.

Italy was the largest electricity importer in 1991, with a total of about 35 TWh or 13 per cent of total world imports and about 14 per cent of its own total consumption. The United States was second with 31 TWh or 11 per cent of total world imports. Although the United States was the second largest importer, its total imports accounted for only 1.0 per cent of its total consumption. The great majority of U.S. electricity imports came from Canada.

Among the top six electricity exporters in 1991, four were also top importers: the United States, West Germany, Switzerland and Canada. Canada is usually a net electricity exporter, however, due to meeting emission guidelines and the problems associated with 1991 water flows, Canada imported a substantial amount of electricity from the United States.

Electricity Intensities

Table 2.7 compares the intensity of electricity use in the economies of all 24 member countries in the Organization for Economic Co-operation and Development (OECD), for the period 1960-91. Electricity intensity is defined as total electricity consumption per dollar of gross domestic product (GDP). To facilitate the comparison, all currencies were converted into U.S. dollars at 1985 price levels and exchange rates. Because of the limited availability of data, only OECD countries are included in the table. Among these countries, Norway had the highest electricity intensity, followed by Iceland, Sweden, New Zealand, Canada, Luxembourg, Portugal and Finland. In 1991, the electricity intensities of these countries were all greater than 1.0 kilowatt hour of electricity consumption per U.S. dollar of GDP, while Switzerland, Japan, Italy, Denmark and the Netherlands all had electricity intensities of less than 0.6.

Canada's high electricity intensity is a result of several factors, including our relatively cold climate and the fact that a host of electricity-intensive industries are located here. In addition, since the first oil embargo of 1973, a shift in energy use from oil to electricity has occurred in all sectors of the economy.

All 24 OECD-member countries experienced a time-trend increase in electricity intensity between 1960 and 1991, although some minor fluctuations occurred in the United States, the United Kingdom and Japan. In fact, electricity intensities have been steadily declining since 1970 for the U.K., suggesting that electricity use in producing output has been reduced.

Electricity Prices

A comparison of international electricity prices is difficult because of different rate schedules, consumption levels and national currencies. Nevertheless, a reasonable comparison has been established by using average revenue per kilowatt hour in a given sector, under a certain level of consumption, and by converting to U.S. dollars. For a more accurate comparison, purchasing power parities should be used when converted to U.S. dollars. However, such parities are not available for some countries covered in this study and are therefore not taken into consideration.

Tables 2.8, 2.9 and 2.10 summarize electricity prices by sector for 28 cities in 18 selected countries in the world. The results indicate that Canada's electricity prices are highly competitive in the residential, commercial and industrial sectors relative to other countries.

Tables referred to in this chapter are on the following pages.

Chapter 2

Tables & Figures

Table 2.1
International Comparison of Installed Generating Capacity, 1991*

Country	Conventional Thermal	Hydro	Nuclear	Geothermal	Total
		(GW)			
United States	583	92	108	5	788
Soviet Union ⅄	241	65	38	0	344
Japan	127	39	33	0	200
China	108	38	0	0	146
Germany ✦	89	9	25	0	123
France	23	25	59	0	107
Canada	**31**	**60**	**13**	**0**	**105**
India	58	20	2	0	80
United Kingdom	54	4	11	0	70
Italy	38	19	0	1	58
Brazil	7	47	1	0	54
Spain	20	16	7	0	44
Australia	28	7	0	0	35
Sweden	8	16	10	0	34
Poland	29	2	0	0	31
Mexico	20	8	0	1	29
Norway	0	27	0	0	27
South Africa	24	1	1	0	26
Korea, Republic of	15	2	8	0	25
Czechoslovakia	15	3	4	0	21
World Total**	1 842 (64.7%)	653 (22.9%)	343 (12.0%)	9 (0.3%)	2 847 (100.0%)

* Includes the 20 countries with the largest electrical systems.

** Total for all 190 countries or areas listed in source reference.

⅄ The former Soviet Union ceased to exist on December 25, 1991.

✦ Represents a unified Germany.

Source: Energy Statistics Yearbook, 1991, United Nations, pp. 332-360.

Table 2.2
International Comparison of Electricity Generation by Fuel Type, 1991*

Country	Conventional Thermal	Hydro	Nuclear	Geothermal	Total
		(TWh)			
United States	2 159	288	613	19	3 079
Soviet Union ⅄	1 266	235	212	0	1 713
Japan	567	106	213	2	888
China	552	125	0	0	678
Germany✦	390	21	163	0	574
Canada	**114**	**308**	**85**	**0**	**508**
France	61	62	331	0	455
United Kingdom	246	6	71	0	322
India	236	68	5	0	309
Brazil	15	218	1	0	234
Italy	173	46	0	3	222
South Africa	164	1	4	0	170
Australia	141	16	0	0	157
Spain	72	28	55	0	156
Sweden	7	64	77	0	148
Poland	131	3	0	0	135
Korea, Republic of	71	5	56	0	132
Mexico	94	24	3	5	126
Norway	0	111	0	0	111
Czechoslovakia	56	3	24	0	83
World Total**	7 681	2 236	2 078	39	12 034
	(63.8%)	(18.6%)	(17.3%)	(0.3%)	(100%)

* Includes the world's 20 largest electrical energy producers.
** Total for all 190 countries or areas listed in source reference.
⅄ The former Soviet Union ceased to exist on December 25, 1991.
✦ Represents a unified Germany.

Source: Energy Statistics Yearbook, 1991, United Nations, pp. 392-420.

Table 2.3
International Comparison of Per Capita Electricity Consumption, 1991*

Country	kWh/Person	As Percentage of World Average
Norway	25 319	1 137
Canada	**18 134**	**814**
Iceland	17 486	785
Sweden	17 008	764
Luxembourg	13 693	615
Finland	13 098	588
United States	12 281	551
Australia	9 045	406
New Zealand	8 635	388
Germany✦	7 199	323
Japan	7 161	322
France	7 044	316
Belgium	7 020	315
Austria	6 747	303
United Kingdom	5 860	263
Soviet Union⅄	5 818	261
Netherlands	5 542	249
Italy	4 452	200
Spain	3 972	178
South Africa	3 709	167
Poland	3 448	155
Korea, Republic of	3 020	136
Brazil	1 723	77
Argentina	1 679	75
Mexico	1 440	65
Egypt	754	34
China	592	27
India	360	16
Nigeria	88	4
World Average**	2 227	100

* The first ten countries are listed according to their actual global rankings. The remaining countries are given in descending order of consumption; however, since only the most populous countries from each region were selected, the list does not indicate their true global rankings.

** Average for all 190 countries or areas included in source reference.

✦ Represents a unified Germany.

⅄ The former Soviet Union ceased to exist on December 25, 1991.

Source: Energy Statistics Yearbook, 1991, United Nations, pp. 422-436

Table 2.4
International Comparison of Total Electricity Consumption Growth Rates, 1988-91

Country	Average, 1988-91
Korea, Republic of	12.2
India	8.4
Spain	8.0
China	7.4
Japan	5.6
Mexico	4.7
Australia	4.1
France	4.1
Brazil	3.9
Italy	3.5
South Africa	2.3
United States	2.2
United Kingdom	1.8
Germany✦	1.6
Norway	1.4
Canada	**0.8**
Sweden	0.7
Soviet Union⅄	-0.02
Czechoslovakia	-2.1
Poland	-4.0
World Total*	2.7

* Total for all 190 countries or areas included in source reference.

✦1991 data represents a unified Germany, while prior years represent West Germany only.

⅄ The former Soviet Union ceased to exist on Dec. 25, 1991.

Source: Calculated from Energy Statistics Yearbook, 1991, United Nations, pp. 422-470.

Table 2.5
International Comparison of Electricity Exports, 1991*

Country	Exports** (GWh)	Production (GWh)	Percentage of Exports to Production
France	58 746	454 702	12.9
Germany✦	26 200	573 752	4.6
Canada	**24 522**	**507 913**	**4.8**
Switzerland	22 578	57 802	39.1
Soviet Union⅄	19 406	1 712 900	1.1
Poland	9 326	134 696	6.9
United States	8 540	3 079 085	0.3
Austria	7 738	51 484	15.0
Sweden	7 519	147 730	5.1
Belgium	6 845	71 945	9.5
Czechoslovakia	6 298	83 274	7.6
Norway	6 039	110 950	5.4
South Africa	5 936	169 645	3.5
Denmark	5 047	36 303	13.9
Spain	3 762	155 704	2.4
Hong Kong	3 061	31 807	9.6
Mexico	2 500	126 375	2.0
Yugoslavia	2 300	78 882	2.9
Uraguay	1 791	7 017	25.5
Portugal	1 620	29 871	5.4
Zambia	1 500	7 775	19.3
Hungary	1 047	30 039	3.5
Luxembourg	780	1 415	55.1
Italy	372	222 041	0.2
Total World Exports***	269 652	12 034 080	2.2

* Includes the world's 25 largest electricity exporters.
** Includes non-cash exchanges.
*** Total for all exporting countries or areas listed in source reference.
✦ Represents a unified Germany.
⅄ The former Soviet Union ceased to exist on December 25, 1991.

Source: Energy Statistics Yearbook, 1991, United Nations, pp. 422-436.

Table 2.6
International Comparison of Electricity Imports, 1991*

Country	Imports** (GWh)	Consumption (GWh)	Percentage of Imports to Consumption
Italy	35 454	257 123	13.8
United States	30 812	3 101 357	1.0
Germany✦	27 500	575 052	4.8
Brazil	26 803	261 161	10.3
Switzerland	19 782	55 006	36.0
United Kingdom	16 442	338 540	4.9
Netherlands	9 778	83 406	11.7
Austria	8 503	52 249	16.3
Hungary	8 409	37 401	22.5
Czechoslovakia	8 107	85 083	9.5
Finland	7 931	65 427	12.1
Romania	7 047	63 959	11.0
Poland	6 708	132 078	5.1
Sweden	6 224	146 435	4.3
Canada	**6 094**	**489 485**	**1.2**
France	5 516	401 472	1.4
Belgium	4 998	70 098	7.1
Luxembourg	4 500	5 135	87.6
Bulgaria	3 716	40 990	9.1
Norway	3 227	108138	3.0
China	3 110	680 400	0.5
Spain	3 083	155 025	2.0
Denmark	3 075	34 331	9.0
Portugal	1 712	29 963	5.7
Greece	1 498	36 457	4.1
Total World Exports***	272 453	12 036 881	2.3

* Includes the world's 25 largest electricity importers.
** Includes non-cash exchanges.
*** Total for all importing countries or areas listed in source reference.
✦ Represents a unified Germany.

Source: Energy Statistics Yearbook, 1991, United Nations, pp. 422-436.

Table 2.7
International Comparison of Electricity Intensity*

Country**	1960	1970	1980	1989	1990	1991
			(kWh/U.S. $1985)			
Norway	1.52	1.83	1.70	1.68	1.68	1.69
Iceland	0.62	1.05	1.20	1.38	1.41	1.32
Sweden	0.71	0.86	1.06	1.30	1.23	1.31
New Zealand	0.59	0.84	1.14	1.24	1.30	1.30
Canada	**0.94**	**1.05**	**1.13**	**1.22**	**1.20**	**1.24**
Luxembourg	0.93	1.56	1.30	1.24	1.31	1.15
Portugal	0.49	0.60	0.86	1.08	1.10	1.13
Finland	0.44	0.66	0.85	0.98	1.02	1.11
Greece	0.24	0.50	0.74	0.96	0.98	0.98
Australia	0.39	0.55	0.70	0.80	0.81	0.84
Turkey	0.19	0.34	0.59	0.81	0.82	0.84
Germany✦	0.43	0.56	0.63	0.63	0.62	0.75
Belgium	0.44	0.55	0.66	0.71	0.71	0.74
Spain	0.34	0.50	0.71	0.73	0.73	0.74
United States	0.47	0.62	0.69	0.66	0.66	0.68
Austria	0.52	0.58	0.62	0.66	0.66	0.67
France	0.35	0.42	0.54	0.62	0.62	0.66
United Kingdom	0.53	0.73	0.69	0.61	0.62	0.64
Ireland	0.33	0.58	0.66	0.64	0.63	0.62
Netherlands	0.30	0.45	0.54	0.56	0.56	0.55
Denmark	0.20	0.39	0.51	0.53	0.52	0.54
Switzerland	0.37	0.37	0.44	0.49	0.51	0.52
Italy	0.36	0.45	0.48	0.50	0.51	0.52
Japan	0.43	0.52	0.53	0.50	0.51	0.51

* Electricity intensity is defined as total electricity consumption per dollar of gross domestic product.

** Due to limited availability of data, table includes only OECD-member countries.

✦ 1991 data represents a unified Germany, while prior years represent West Germany only.

Source: Real gross domestic product in U.S. dollars was obtained from National Accounts, 1960-1990, Dept. of Economics and Statistics, OECD, February 1993. Electrical energy data were obtained from Energy Statistics Yearbook, United Nations, various issues.

Table 2.8
International Comparison of Electricity Prices in the Residential Sector, January 1994

City	Country	Residential Prices (U.S. cents/kWh)
Geneva	Switzerland	15.74
Stockholm	Sweden	15.14
New York	United States	14.96
Sao Paulo	Brazil	14.11
Brussels	Belgium	12.92
Madrid	Spain	12.46
Boston	United States	12.36
Chicago	United States	10.97
Detroit	United States	10.61
Rotterdam	Holland	10.28
Taipei	Taiwan	9.62
Houston	United States	9.33
Bankok	Thailand	8.72
Singapore	Singapore	8.49
Kuala Lumpur	Malaysia	8.37
Toronto	**Canada**	**7.91**
London	United Kingdom	7.86
Minneapolis	United States	7.82
Oslo	Norway	6.31
New Delhi	India	6.16
Ottawa	**Canada**	**6.02**
Calgary	**Canada**	**5.62**
Portland	United States	5.62
Vancouver	**Canada**	**5.31**
Montreal	**Canada**	**5.26**
Sydney	Australia	5.19
Winnipeg	**Canada**	**5.07**
Seattle	United States	4.05

Source: Canadian data were obtained from the Electricity Branch, Department of Natural Resources Canada. Data for other countries were obtained from a survey undertaken by the Electricity Branch, Natural Resources Canada, February 1994.

Table 2.9
International Comparison of Electricity Prices in the Commercial Sector, January 1994

City	Country	Commercial Prices (U.S.cents/kWh)
Stockholm	Sweden	21.46
Geneva	Switzerland	16.09
New York	United States	15.42
Brussels	Belgium	12.15
Detroit	United States	10.99
Boston	United States	10.87
Rotterdam	Holland	10.52
Madrid	Spain	10.43
Sydney	Australia	10.19
Chicago	United States	9.62
Taipei	Taiwan	8.58
Toronto	**Canada**	**8.56**
Kuala Lumpur	Malaysia	8.44
Houston	United States	8.36
Sao Paulo	Brazil	8.30
New Delhi	India	8.27
Bangkok	Thailand	8.06
London	United Kingdom	7.06
Montreal	**Canada**	**7.05**
Singapore	Singapore	6.92
Minneapolis	United States	6.48
Calgary	**Canada**	**6.48**
Oslo	Norway	6.23
Ottawa	**Canada**	**6.22**
Winnipeg	**Canada**	**5.43**
Portland	United States	5.37
Vancouver	**Canada**	**5.10**
Seattle	United States	4.47

Source: Canadian data were obtained from the Electricity Branch, Department of Natural Resources Canada. Data for other countries were obtained from a survey undertaken by the Electricity Branch, Natural Resources Canada, February 1994.

Table 2.10
International Comparison of Electricity Prices in the Industrial Sector, January 1994

City	Country	Industrial Prices (U.S. cents/kWh)
Stockholm	Sweden	14.58
Geneva	Switzerland	11.60
New York	United States	10.50
Brussels	Belgium	10.05
New Delhi	India	8.76
Boston	United States	8.14
Madrid	Spain	8.03
Rotterdam	Holland	7.66
Detroit	United States	7.50
Chicago	United States	7.49
Bankok	Thailand	7.22
Taipei	Taiwan	6.83
Sao Paulo	Brazil	6.77
Toronto	**Canada**	**6.53**
Houston	United States	6.50
Kuala Lumpur	Malaysia	6.27
London	United Kingdom	6.18
Singapore	Singapore	6.10
Sydney	Australia	5.94
Oslo	Norway	5.54
Ottawa	**Canada**	**5.22**
Minneapolis	United States	4.93
Calgary	**Canada**	**4.24**
Vancouver	**Canada**	**4.24**
Montreal	**Canada**	**4.11**
Portland	United States	3.95
Winnipeg	**Canada**	**3.62**
Seattle	United States	3.59

Source: Canadian data were obtained from the Electricity Branch, Department of Natural Resources Canada. Data for other countries were obtained from a survey undertaken by the Electricity Branch, Natural Resources Canada, February 1994.

Regulatory Structures

Federal Regulation

The Constitutional Framework

Canada is a federal state. The power to make laws is divided between the federal government and the provincial governments. Each level of government has independent authority, set out in the *Constitution Act, 1867*, to make laws in certain areas. Within its own area of authority, each level of government is autonomous.

The *Constitution Act, 1867*, divides legislative power between the Parliament of Canada and provincial legislatures. It states that each legislative body may make laws relating to certain classes of subjects. This distribution of powers is listed in sections 91 and 92 of the Act, supplemented by section 92A, which was added in 1982.

Generally speaking, the classes of powers listed in sections 91 and 92 do not overlap: a particular class is assigned to either the Parliament of Canada or to the provinces but not to both. The *Constitution Act, 1867*, can be thought of as defining two mutually exclusive domains of legislative authority.

There are two important qualifications to this exclusivity: in certain areas concurrent powers are assigned to both levels of government, in other areas, each level may have authority to enact laws, based on its list of powers. If there is a direct conflict between the federal and provincial laws in either case, the federal law is paramount.

Energy is not specifically mentioned in sections 91 and 92, although it is referred to in section 92A. Laws that purport to regulate one or another aspect of energy production, transportation, and utilization thus derive their constitutional validity from two sources: (i) those parts of section 91 and 92 that are relevant to the specific energy activity in question, and (ii) section 92A, which deals specifically with natural resources and electrical energy.

Electricity generation systems mostly fall within provincial jurisdiction; they are "local works and undertakings" under section 92(10) of the *Constitution Act, 1867*. Section 92A(1)(c) reinforces this principle. It assigns to the provinces explicit responsibility for "sites and facilities in the province for the generation and production of electrical energy."

The only exception to the above is nuclear power. In 1946, with the passage of the *Atomic Energy Control Act,* the Canadian Parliament declared that all works and undertakings for the production, use and application of atomic energy are for the general advantage of Canada. The effect of this declaration was to place nuclear generation facilities within Canadian government jurisdiction, under sections 92(10)(c) and 91(29) of the *Constitution Act, 1867*. (Section 91(29) assigns to the Parliament of Canada all classes of subjects not exclusively assigned to the provinces. Section 92(10)(c) states that the provinces will not have jurisdiction over local works and undertakings declared by Parliament to be for the general advantage of Canada.)

Jurisdiction over international and interprovincial transmission systems derives from sections 92(10)(a) and 91(29). Section 92(10) assigns general responsibility for "local works and undertakings" to the provinces. It then goes on to list certain exceptions. One exception, stated in section 92(10)(a), is any work or undertaking connecting one province to another or extending beyond the limits of a province. Section 91(29) states that any class of subject not assigned exclusively to the provinces shall be within the power of the Canadian Parliament. Thus the effect of sections 92(10)(a) and 91(29) taken together is to confer upon the Parliament of

Canada exclusive legislative authority over transportation undertakings that cross interprovincial boundaries or the international boundary.

Provincial authority over interprovincial transmission systems derives from section 92(10), which allocates to the provinces authority over works and undertakings that are solely provincial in nature.

Section 91(2) confers upon the Parliament of Canada exclusive legislative authority on matters relating to "the regulation of trade and commerce." This is the primary basis upon which the Canadian government regulates electricity exports. Federal jurisdiction over electricity exports may also be derived from sections 92(10) and 91(29), which enable the Parliament of Canada to legislate with respect to international undertakings; this power extends to the marketing of the products transported by such undertakings.

With regard to the regulation of interprovincial electricity sales, the *Constitution Act, 1867* defines concurrent powers. Federal authority is derived principally from the trade and commerce power, section 91(2). Provincial authority derives from section 92A(2), which gives the provinces the power to make laws respecting the export of energy to other parts of Canada, provided that such laws do not discriminate with respect to price or to supply. If a conflict between federal and provincial laws over interprovincial trade should arise, the federal law will prevail. Federal paramountcy in this regard is explicitly stated in section 92A(3).

The above brief summary of the constitutional principles governing electricity in Canada indicates quite clearly that the powers of the Parliament of Canada, extensive though they may be on matters of trade, are quite limited insofar as electricity matters generally are concerned. The constitution assigns to the provinces exclusive jurisdiction over electricity matters that are wholly intraprovincial in nature, and it assigns to the provinces concurrent powers with respect to interprovincial trade. Furthermore, it is the ability of the provincial utilities to enter into purchase and sales agreements, combined with the electricity supply policies of the provincial governments, that primarily determine both the nature and the extent of Canadian electricity trade. The Canadian government, if it is to achieve policy objectives relating to electricity, can therefore achieve very little by acting unilaterally. First and foremost, it must seek provincial consensus and provincial cooperation.

Based on the above-mentioned constitutional framework, two federal regulatory agencies have been established to regulate electricity trade and nuclear energy. Environmental matters related to energy projects are handled by Environment Canada. Provincial regulatory agencies have also been established to implement regulation on electrical energy demand, supply, pricing, and environment assessment on power projects in the provinces.

National Energy Board

The National Energy Board (NEB) is a federal tribunal, created in 1959 by an Act of Parliament. The Board's powers and duties are derived from the *National Energy Board Act.* Under the Act, the Board advises the federal government on the development and use of energy resources, and regulates specific matters concerning oil, gas and electricity. The Board's jurisdiction over electrical matters is limited to the certification of international and designated interprovincial power lines and the licensing of electricity exports from Canada. The Board has no jurisdiction over imports of electricity.

On September 6, 1988, a new policy concerning the regulation of electricity exports and

international power lines was announced. Legislation amending the *NEB Act* to give effect to this policy (Bill C-23) was proclaimed on June 1, 1990.

Under the new policy, the Government of Canada will continue to authorize international power lines and exports of electricity. Such authorizations will be of two kinds: (i) permits, which will not require a public hearing or Governor in Council approval; or (ii) licenses (in the case of electricity exports) or certificates (in the case of power lines), which will require a public hearing and Governor in Council approval.

Authorizations will normally be by an NEB-issued permit unless the Governor in Council, on the advice of the Board, designates the application for certification or licensing. Designations are not likely to occur, except in cases where there is evidence that the export applicant has not taken into consideration (a) the effect of the exportation of the electricity on provinces other than that from which the electricity is to be exported; (b) the impact of the exportation on the environment; and (c) whether the applicant has offered electricity to be exported to domestic buyers under the same terms and conditions.

Once an application is designated, the Board will conduct a public hearing, and it will not issue a licence or certificate unless it is fully satisfied that the proposal is in the Canadian public interest. Licences and certificates will not be issued unless they are also approved by the Governor in Council.

Under the amendments to the *NEB Act*, Part III.1 provides for the federal regulation of international power lines. In determining whether to recommend to the Governor in Council designation of a power line, the Board will have regard to all relevant considerations, including: (i) the effect of the power line on other provinces; (ii) the impact of construction and operation of the power line on the environment; and (iii) any other matters that may be specified in the regulations.

In making its determination, the Board will seek to avoid the duplication of measures taken by the applicant and the relevant provincial government(s). The NEB will continue to authorize the general corridor through which an international power line will pass. However, the precise location of the line within this corridor will normally be determined by provincial regulatory procedures, and any expropriation that may be necessary will be done under provincial laws. The only exception to this general procedure will be in cases where the applicant elects to have federal law apply.

The Governor in Council may by order, designate a particular interprovincial power line for regulation in the same manner as international power lines. When power from one province simply enters the grid of another province, there is no federal regulation.

Part VI of the amended *NEB Act* includes a Division II, which provides for the regulation of electric power exports. The maximum duration of export licences and permits will be 30 years. In determining whether to recommend to the Governor in Council designation of an application for export, the board will have regard to all relevant considerations, including: (i) the effect of the export on provinces other than that from which the electricity is to be exported; (ii) whether those wishing to buy electricity for consumption in Canada have been granted fair market access to the electricity proposed for export; (iii) the impact of the export on the environment; and (iv) any other matters that may be specified in the regulations. In making its determination, the Board will also seek to avoid the duplication of measures taken by the applicant and the sponsoring provincial government.

Atomic Energy Control Board

Immediately after World War II, Canada began to study the question of how to encourage the use of nuclear energy for peaceful purposes. In 1946, Parliament passed the *Atomic Energy Control Act* with this objective in mind.

The Act gave the federal government control over the development, application and use of nuclear energy and established the Atomic Energy Control Board (AECB). The five-member Board administers and enforces the Act, from which it derives its authority to regulate the health, safety, security and environmental aspects of nuclear energy. The AECB reports to Parliament through a designated Minister, currently the Minister of Natural Resources Canada.

The Board's primary function is to license Canadian nuclear facilities and activities dealing with prescribed substances and equipment. Nuclear facilities include power and research reactors, uranium mines and refineries, fuel fabrication plants, heavy water plants, waste management facilities and particle accelerators. Prescribed substances include uranium, thorium, heavy water and radioisotopes. Activities relating to such substances, which may be licensed, include production, processing, sale, use, import and export. Before issuing a licence, the AECB ensures that the appropriate health, safety and security standards are met.

The AECB's control also extends to international security of nuclear materials and technology. Through the licensing process, it ensures that nuclear equipment and supplies are exported only in accordance with Canada's obligations under the Treaty on the Non-Proliferation of Nuclear Weapons.

Provincial Regulation

As noted above, under the Canadian Constitution the provinces have legislative authority over the generation, transmission and distribution of electricity. In most provinces some form of regulation exists, and most provinces have established regulatory bodies to oversee the utilities, although the degree of supervision varies. The major areas subject to review are rate-setting and the construction of new facilities. The nature of provincial regulation with respect to these matters is described briefly below. The environmental regulations of the provinces are described in Chapter 4.

Newfoundland

Newfoundland Light & Power Company (NLPC) and Newfoundland and Labrador Hydro (NLH) are regulated by the Newfoundland Board of Commissioners of Public Utilities. The Board fully regulates the rates and policies of NLPC, including the construction of new facilities. Since 1977, the Board has also had authority under the *Electric Power Control Act* to review NLH's rates for residential customers. The Board makes recommendations to the Newfoundland Cabinet, which is the final authority for utility rates.

Cabinet is also the final authority with respect to NLH's capital expenditure program. Proposals by NLH for new facilities must receive Cabinet approval before construction can begin. NLPC must receive the approval of the province's Board of Commissioners of Public Utilities before proceeding with the construction of new facilities.

Prince Edward Island

Maritime Electric Company Limited is regulated by the Island Regulatory and Appeals Commission of Prince Edward Island (formerly

the Public Utilities Commission of Prince Edward Island) under the provisions of the *Electric Power and Telephone Act.* The Commission has decision-making authority over electric utility rates in the province and screens all proposals for the construction of new generation and transmission facilities. If the Commission believes that a new facility may adversely affect the environment, a formal environmental assessment review process is initiated. A description of this process is provided in Chapter 4.

Nova Scotia

Since 1976, the Nova Scotia Board of Commissioners of Public Utilities, in accordance with the provincial *Public Utilities Act*, has had full decision-making power over the utility's rates and policies.

The Board's authority extends to the construction of new facilities, and utilities are required to apply directly to the Board when planning new generation or transmission facilities. As part of the review process, the Board holds public hearings, during which the utility presents its proposed project, costs and alternative plans. Members of the public may intervene directly during a hearing. The Board of Commissioners is the final authority on new facilities.

Nova Scotia Power Corporation was privatized in August 1992 changing its name to Nova Scotia Power Incorporated (NSPI). However, the Nova Scotia Public Utilities Board, in accordance with the *Public Utilities Act*, remains the final authority regarding NSPI's rates and development plans.

New Brunswick

As a Crown corporation, New Brunswick Power reports to the provincial government through its chairman, who is a member of the Cabinet. Rates and operations are regulated by a nine-member Board of Commissioners appointed by the Lieutenant Governor of New Brunswick. The utility's chairman and vice chairman sit on the Board. The Board's recommendations are referred to the provincial Cabinet, which is the final regulatory authority. A bi-partisan Crown corporation committee also reviews utility rates and operations annually.

NB Power must receive approval from Cabinet before proceeding with the construction of new facilities. Although Cabinet is the final authority in this regard, its decision is based upon a recommendation from the Minister of Municipal Affairs and Environment, following an evaluation of the project's possible environmental impacts. New Brunswick's environmental impact assessment process is described in Chapter 4.

Quebec

In Quebec, the National Assembly's committee on economics and employment reviews Hydro-Québec's long-term development plan, which includes any proposed rate changes. The committee then makes a recommendation to the Minister of Energy and Resources, who in turn makes a recommendation to Cabinet. Rate increases can therefore be implemented by Hydro-Québec only after they have been approved by Cabinet.

The construction of new facilities by Hydro-Québec can take place only after the utility has received an Order-in-Council from the provincial government. Before an Order is issued, the Department of the Environment and the Department of Energy and Resources must approve plans for the new facility. Other departments and agencies are also consulted.

Ontario

Ontario Hydro is a provincially owned corporation, which reports to the government through the Minister of Energy. The management of Ontario Hydro is under the direction and control of its Board of Directors. Proposed rate changes are referred to the Ontario Energy Board (OEB), through the Minister of Energy, for examination at public hearings. However, it is the Board of Ontario Hydro that is authorized to set the utility's rates, and it may accept or reject the recommendations of the OEB.

On matters concerning its generation expansion program and transmission facilities, Ontario Hydro is regulated by the provincial Joint Hearing Board. The Board is composed of members from the Environmental Assessment Board and the Ontario Municipal Board. The Joint Board makes a recommendation to the provincial government, and final approval must be given through an Order-in-Council.

Manitoba

Under the *Manitoba Crown Corporations Public Review and Accountability Act* of 1988, Manitoba Hydro's proposed changes to domestic rates must be reviewed by the Manitoba Public Utilities Board, which holds a public review and makes a final decision on the proposal.

Under the 1988 *Manitoba Environment Act*, the provincial government must also approve major facility construction. Applications are made to the Minister of the Environment and a full environmental assessment is required. A description of Manitoba's environmental assessment review process is given in Chapter 4.

Saskatchewan

Saskatchewan Power Corporation (SaskPower) is governed by a government-appointed Board of Directors that is responsible for the management and operation of the Crown utility. Proposals to increase rates or construct new generation or transmission facilities must be approved by the Board of Directors. The minister responsible for SaskPower is a member of the Board.

Alberta

TransAlta Utilities Corporation and Alberta Power Limited are investor-owned electric utilities in Alberta. They are regulated by the Alberta Energy Resources Conservation Board (ERCB) with respect to the development of generation and transmission facilities, coal mine developments and changes in service areas. Thermal generating stations are issued permits, which are subject to Lieutenant Governor in Council approval, while hydro dam approvals require final authorization through the passage of a bill in the legislature. TransAlta's and Alberta Power's rates are regulated by the Alberta Public Utilities Board, under the provisions of the *Public Utilities Board Act* of 1980.

As a municipally owned utility, Edmonton Power is subject to the authority of Edmonton Council, as well as the various provincial regulatory bodies. Its rates and financing are regulated by city council, while the ERCB is responsible for the regulation of new generation and transmission facilities.

The three utilities participate in the cost-pooling program of the Electric Energy Marketing Agency (EEMA). The EEMA was established in 1982 by the provincial government to help equalize power costs throughout Alberta. Under EEMA legislation, the utilities' generation and transmission costs are regulated by the Public

Utilities Board. The Board also approves the selling prices of electricity to EEMA, which then pools the utilities' costs and resells the power at average prices back to the utilities. In the Fall of 1991, the provincial government established a panel to review the equalization policy. The panel released a report on the status of the EEMA in February 1993, recommending that transfer payments be provided only when costs exceed EEMA average by 6 per cent.

British Columbia

Electricity rate changes in the province of British Columbia require the approval of the British Columbia Utilities Commission (BCUC). Major generation and transmission projects require the approval of the provincial Cabinet. Upon receiving an application to construct a major facility, the government may refer the application to the BCUC for review and a recommended course of action. Projects that obtain Cabinet approval receive an Energy Project Certificate from the province.

Yukon

The Yukon Energy Corporation and the Yukon Electrical Company are regulated by the Yukon Utility Board, under the *Public Utilities Act of 1986*. Under this Act, the Corporation and Company must file applications for rate changes or facility construction with the Board, which reviews the applications and makes a decision.

Northwest Territories

The Northwest Territories Power Corporation and Northland Utilities Enterprises Limited are regulated by the *Northwest Utilities Act* of 1989. Under the Act, they must file an application with the N.W.T. Public Utilities Board in order to receive authority for rate changes or facility development. Upon receiving an application, the Board holds a public hearing and then reaches a decision, which is final.

Electricity Regulatory Agencies

Canada:

- National Energy Board
- Atomic Energy Control Board

Provinces:

- Newfoundland Board of Commissioners of Public Utilities
- Nova Scotia Board of Commissioners of Public Utilities
- New Brunswick Board of Commissioners
- Quebec Legislative Assembly
- Ontario Energy Board (Rates)
- Ontario Joint Hearing Board (Generating & Transmission)
- Manitoba Public Utilities Board
- Saskatchewan Legislature
- Alberta Energy Resources Conservation Board (G&T Plans)
- Alberta Public Utilities Board (G&T Costs)
- Electrical Energy Marketing Agency (Prices)
- British Columbia Utilities Commission
- Yukon Utility Board
- Northwest Territories Public Utilities Board

Chapter 4

Electricity and the Environment

Energy is the engine of economic growth. It is also a major source of pollution. The need to develop relatively inexpensive sources of energy as a basis for economic growth, and increasing public pressure to limit environmental damage, present a major challenge to governments and utilities. In Canada, the task of balancing energy requirements and environmental demands is being handled in a number of ways including environmental impact analyses, development and application of techniques to reduce emissions and long term shifts in the fuel mix used to generate power.

Most, if not all, energy generation and transmission projects have some impact on the environment. These range from chemicals contained in flue gases to the effect on plant and animal life when clearing a way for transmission lines. Not all of these impacts are necessarily harmful or permanent and some are even seen as beneficial. The most significant of these impacts are identified briefly as follows:

Impacts Attributable to Electricity Generation

Coal-Fired Generation

Roughly sixty per cent of the energy produced in coal combustion is in the form of waste heat emanating from either the stack or the cooling water. Flue gases include a number of chemicals including sulphur dioxide and nitrogen oxides (which are major components of acid precipitation), hydrocarbons (which combine with nitrogen oxides in the atmosphere to produce low-level ozone which - in high concentrations - can harm certain crops) and carbon dioxide which may contribute to higher global mean temperatures. Other by-products of coal combustion include contaminated solid wastes and process waters.

Oil-Fired Generation

Oil-fired generation is generally considered to be less harmful than coal-fired because sulphur is removed from the oil during the refining process. However, exhaust gases still contribute carbon monoxide, sulphur dioxide, nitrogen oxide, hydrocarbons and carbon dioxide to the atmosphere.

Natural Gas Fired Generation

Hydrogen sulphide is removed from natural gas before shipment so that the principal by-products of combustion are carbon dioxide and water.

Hydro-Electric Generation

Environmental impacts result from dam construction at the reservoir site as well as downstream. These include the effect on the local climate, vegetation, fish and wild life caused by the creation or expansion of a reservoir and the construction of a dam and generating station. Water levels and flows are affected above and below the dam as are the nutrient content and temperatures of water bodies. Some of these impacts could be positive, including the reduction of seasonal flooding and the creation of possible new wild life reserves.

Nuclear Generation

Unlike the combustion of fossil fuels, nuclear generation does not produce any significant amounts of gaseous emissions. Indeed, environment impact is one area where nuclear energy may have a significant advantage. Nevertheless, safety and the management of radioactive wastes pose a challenge to the nuclear industry, both technically and in terms of public acceptance.

Impacts Attributable to Electricity Transmission

Construction of Transmission Lines

Many of the effects caused by line construction are temporary, including the disruption of wild and aquatic life, as well as noise and air pollution. However, where vegetation is cleared to make a right of way, local soil erosion and increased sedimentation of water bodies can result.

Operation and Maintenance of Transmission Lines

Plant and wild life along the right of way can be affected by herbicide application and cut-backs of vegetation. Other underground installations (such as a pipeline) might also be damaged due to the operation of a ground electrode and studies are currently underway to determine whether the lines' extra low frequency electro-magnetic fields are a danger to health.

Other Possible Contaminants

Polychlorinated Biphenyls (PCBs).

Because of their excellent insulating and thermal properties, PCBs are used in electrical equipment insulating oils. Current evidence suggests that there is no positive link between work place exposure to PCBs (as such) and the likelihood of contracting cancer. However, when involved in transformer or capacitor fires, PCBs release highly toxic substances called polychlorinated dibenzofurans (PCDF).

Acid Rain

Acid rain or acid precipitation, is the term given to the rain, snow, sleet, hail, frost or dew which contain sulphuric and nitric acids. Such acids can come from the atmospheric conversion of sulphur and nitrogen oxide (SO_x and NO_x) emissions. Around the world, up to half of the sulphur in the air comes from natural sources such as rotting vegetation, plankton, and in some places, volcanoes.

However, the principal sources of sulphur oxide emissions in North America are coal-fired power generating stations and non-ferrous ore (i.e., nickel, copper, lead and zinc) smelters. Coal-fired generating stations are the main source of sulphur emissions in the U.S., whereas in Canada 60 per cent come from smelters. The main source of nitrogen oxide emissions in both countries are vehicle exhausts.

U.S. emissions exceed Canadian by a factor of 5 for sulphur oxide and 10 for nitrogen oxide, but both countries contribute to each others problems through long-range atmospheric transportation of airborne pollutants. It is estimated that 80-90 per cent of the acid rain affecting Canada is attributable pollutants originating in the U.S.

The Greenhouse Effect

Life is possible on earth because of the existence in the atmosphere of a number of important gases, including carbon dioxide (CO_2), nitrous oxide (N_2O),ozone (O_3) and methane (CH_4). These gases behave as an insulating blanket, absorbing much of the heat escaping from the earth's surface and thereby trapping warmth within the lower atmosphere. This "greenhouse effect" is a natural phenomenon without which the earth's surface would be 30 degrees celsius colder, and uninhabitable to most existing life forms.

The issue is the relatively rapid increase in the build up of these greenhouse gases primarily as a result of the burning of fossil fuels and other industrial and agricultural processes, and the

effect some scientists believe this will have on global temperatures and, ultimately, on the world's climate and ocean levels.

Burning of fossil fuels (coal, oil and natural gas) to produce energy releases carbon dioxide and nitrous oxide into the atmosphere and also contributes to increased levels of surface ozone.

The most significant of these greenhouse gases is carbon dioxide. Since 1860, atmospheric CO_2 concentrations have risen from 270-290 ppmv (parts per million by volume) to nearly 350 ppmv today. Projections of CO_2 trends are subject to large uncertainties, but many scientists believe that concentrations of this and other greenhouse gases could double by the middle of the next century.

Responses to Environmental Impact of Electricity Generation and Transmission

A number of measures have been implemented by governments and industry to monitor and reduce the environmental impacts of electricity generation and transmission. These include the employment of technologies, fuel mix changes, studies and the development and application of government policies, standards, codes of practice and regulations. The most important of these are identified briefly in this summary and in more detail in separate notes.

Technological Measures

These measures are often introduced in response to government regulations and standards. Many are designed to reduce sulphur and nitrous oxide emissions (major contributors to acid precipitation) and include a number of flue gas desulphurization technologies, circulating fluidized bed combustion, low nitrous oxide burners, coal blending and cleaning and co-generation.

Switch to Environmentally More Benign Fuels

Although all methods of generating energy have an impact on the environment, some are considered to be less harmful than others. A decline in the relative importance of thermal generation (by fossil fuels - coal, oil and natural gas) and an increase in that of hydro and nuclear will reduce the emission of atmospheric pollutants, even where fossil fuel plants have been fitted with emission controls. The experience in Canada is mixed: the relative importance of fossil fuels declined from 23 per cent in 1970 to 17 per cent in 1987 but as total electricity generation more than doubled over this same period, there was an actual growth in thermal generation (from 47 to 78 terawatt hours) over this same period with a real decline only being registered in the last few years. Again, although the actual amount of hydro-electric power generated doubled between 1970 and 1987, its relative importance declined from 77 per cent to 66 per cent, while that of nuclear rose from under 1 per cent to 17 per cent.

Studies

Methodologically sound studies can play a major role in establishing the existence and nature of environmental impacts and are therefore a necessary first stage in the response. A number of current studies focus on determining whether or not some link exists between extra low frequency electromagnetic fields and various forms of cancer. The most interesting of these studies include one financed by Ontario Hydro, Hydro-Québec and Electricité de France and another by the U.S. Electric Power Research Institute. Other important areas of study focus on PCBs, acid rain and the so-called "Greenhouse Effect". Another interesting study entitled "Project 88: Harnessing Market Forces to Protect our Environment: Initiatives for the New President," was produced by a team of experts and sponsored by Senators Wirth

(Democrat-Colorado) and Heinz (Republican-Pennsylvania). This study focuses on economic tools that might be used to solve environmental problems relating to energy, climate change, land use and resource management.

Setting Emission Targets

The most important of these is the federal government's agreement with seven provincial governments to set limits on sulphur oxide emissions, which should result in a 50 per cent reduction by 1994 when compared to a 1980 base. Canada is also a signatory of the 1979 Helsinki Protocol on Sulphur Dioxide thereby agreeing to reduce transboundary emissions by 30 per cent by 1993 when compared to a 1980 base.

Concern with the effects of acid rain and the fact that important constituents of it can be carried in the atmosphere for considerable distances, has led to the establishment of emission limits and the development of transboundary emission accords.

In March 1985, the Canadian government announced a comprehensive program involving working with provincial governments and industry to reduce sulphur oxide emissions by 50 per cent by 1994 when compared to a 1980 base. As control of such emissions lie principally within provincial jurisdiction, it was necessary for all seven provinces involved to enter into a federal-provincial agreement to give effect to the overall target. This was done in December 1987, when the last of the seven provinces, Nova Scotia, signed the agreement with the federal government.

The sulphur oxide emission reduction targets for 1994 are set out in Table 4.1.

Environmental Assessment Review Processes

As was pointed out earlier, electricity generation and transmission projects have some impacts on the environment. Governments, industry and other groups in society have recognized the need to assess and reduce these impacts. For their part, federal and provincial governments have established processes that are designed to reduce the environmental consequences of electrical generation and transmission.

Despite differences from one province to another in the nature of the environment and in the scale and type of project proposed, there are some similarities in the processes developed by the various provincial governments to ensure that the development of electricity generation and transmission projects does minimum damage to the environment.

In most provinces, the proponent (a person, company, provincial agency or Crown corporation) is responsible for conducting an environmental assessment of activities. A lead agency (often in the department responsible for the environment) is normally appointed to review this assessment on behalf of the provincial government.

In all 10 provinces, decision-making occurs in discrete steps. Small, routine projects with no significant impacts are first screened out and allowed to proceed with a minimum loss of time and expense. Projects that may adversely affect the environment are submitted for a more detailed (and sometimes more visible and structured) review. Such projects could be subject to public review by an independent board or panel.

The Environmental Impact Statement (EIS) is used in most provinces and by the federal government to assess projects that may have a major adverse environmental impact. The EIS

format is similar in all jurisdictions and involves (i) a project description, (ii) an analysis of how the project will affect the environment, and (iii) a description of proposed measures to reduce environmental impacts. It is normally prepared by the project proponent and is reviewed by the lead and other government agencies or by a public review board or panel.

The EIS process usually involves some form of public review, but the degree of formality varies among provinces, from formal legal procedures to informal community meetings. At both the federal and provincial levels, the final decision-maker is usually an elected official or officials -- a Cabinet minister or the entire Cabinet. This is the same as in the power regulation processes stated in Chapter 3.

The processes in place in Canadian jurisdictions are outlined below. Some of this material is reviewed in more detail in a report prepared by the Canadian Council of Ministers of the Environment (CCME).[1] Since this 1985 report was completed, British Columbia, Saskatchewan, Manitoba, New Brunswick, Prince Edward Island, and Newfoundland have introduced major changes, and these are reflected in this chapter. In addition, an Environmental Assessment Act was passed in Nova Scotia in 1988 and was proclaimed in July 1989. Alberta's Environmental Protection and Enhancement Act was passed in the summer of 1992 and went into effect September 1, 1993.

[1] William J. Couch, Ph.D. (ed), *Environmental Assessment in Canada: 1985 Summary of Current Practice in Canada.* (Ottawa, Canadian Council of Resource and Environment Ministers, 1985, catalogue number EN 104-4/1985.)

Federal Process

The Federal Government's Environmental Assessment Review Process

In December 1973, Cabinet established the federal Environmental Assessment Review Process (EARP) to ensure that the environmental effects of all federal proposals are assessed early in the planning process. A federal proposal is one initiated by a federal agency, or one that involves federal funding, federal property, or affects an area of federal responsibility. Federal Crown corporations are not bound by the Cabinet decision, but they are invited to participate in the process.

Under EARP, federal departments are responsible for assessing their own proposals. They conduct an initial screening to determine whether a given proposal will have significant environmental effects. If no such effects are perceived, the project may go ahead with appropriate monitoring by the initiating department. The results of all such decisions are published in summary form.

If potentially significant environmental effects are perceived, a formal review process is undertaken by an Environmental Assessment Panel created by the Minister of the Environment. The Panel is assisted in its work by the Federal Environmental Assessment Review Office. The Panel normally requires that the sponsor of the proposal prepare an EIS. If the Minister of the Environment and the initiating minister concur, the scope of the Panel may be broadened to include general socioeconomic effects and the need for the project.

Public participation is an integral part of the assessment process. Any person or organization with an interest in the proposal is provided with an opportunity to appear before the Panel.

Once a Panel has completed its deliberations and evaluated all information on a proposal, it prepares a report containing its findings and recommendations. A Panel could recommend that a proposal not proceed, that it proceed as planned, or that it proceed subject to certain terms and conditions. The recommendations are submitted to the Minister of the Environment and the initiating minister, who must decide (i) to whom the recommendations are directed, (ii) to what extent they should be incorporated into terms and conditions governing the project, and (iii) in what manner they are to be made public. In the event of a disagreement between the two ministers, the question may be submitted to Cabinet.

Following the publication of a green paper in 1987 that identified a number of possible changes to the EARP process[2], the Federal Environmental Assessment Review Office (FEARO) has carried out extensive consultations with the public, and federal departments and agencies. Bill C-78, introducing a new Canadian Environmental Assessment Act (CEAA), was tabled in the House of Commons on June 18, 1990, and was discussed but not concluded in the 1990 session. Bill C-78 was reintroduced as Bill C-13 in the House of Commons on May 29, 1991. The CEAA received Royal Assent in June 1993 and is currently awaiting proclamation. Four key regulations addressing implementing issues were pre-published in the Canada Gazette Part I in September 1993. They are:

- the Law List - a list of statutes that trigger a Federal environmental assessment;
- the Comprehensive Study List - a list of projects considered important enough to warrant a mandatory detailed study;
- the Inclusion List - a list of activities that require assessment; and
- the Exclusion List - a list of projects that are excluded from assessment.

Prior to the publication, the regulations were the subject of an extensive public consultation through the Regulatory Advisory Committee (RAC), established by FEARO in 1992. Industry representatives on the RAC included the Mining Association of Canada, the Canadian Association of Petroleum Producers, the Canadian Electrical Association, the Canadian Nuclear Association, the Canadian Pulp and Paper Association, and environmental groups as well as native groups.

Over a period of 16 months, the RAC attempted to reach consensus on the regulations. In the end, consensus was reached on some provisions but many remained highly contentious. The proclamation of CEAA is anticipated in late 1994. At that time, the Federal Environmental Assessment Review Office will be replaced by the Canadian Environmental Assessment Agency.

Provincial Processes

British Columbia

The principal legal basis for British Columbia's energy project review process is the Utilities Commission Act, 1980. Major energy projects cannot proceed until the proponent has received approval by means of an Energy Project Certificate, a Ministers' Order, or a Certificate of Public Convenience and Necessity, all of which set out the terms and conditions under which the facility may be constructed and operated.

In the Spring 1994 Session of the Legislature, the Government of British Columbia introduced the new Environmental Assessment Act. The

[2] Environment Canada, *Reforming Environmental Assessment: A Discussion Paper.* (Ottawa, Minister of Supply and Services Canada 1987, catalogue number EN 106-5/1987.)

Act established a single, comprehensive process for the identification of the potential effects of major projects and the evaluation of the means to prevent or mitigate adverse impacts. The process ensures that projects are constructed and operated in a manner designed to avoid or reduce environmental and other adverse impacts and provide economic and social benefits over the long term, thereby supporting sustainability.

This Act provides an open, accountable, effective and efficient process which involves the public throughout. This process will be consistent and fair in its application, thus providing certainty and balance for environmental interests, business interests and the public.

The Act is a logical successor to processes that are now used to assess certain major projects, superseding the current Mine Development Assessment Process, Energy Project Review Process and Major Project Review Process.

To administer the Act, an Environmental Assessment Office was established and is headed by an Executive Director who is responsible for overall administration of the environmental assessment process.

Alberta

Alberta's Environmental Impact Assessment (EIA) process was established by the Land Surface Conservation and Reclamation Act of 1973. Pursuant to Section 8 of the Act, the Minister of the Environment may require the proponent of a proposed development to prepare an EIA report if he or she believes it is in the public interest to do so. The purpose of an EIA is to provide information to the public and the government to enable early identification and resolution of significant adverse effects on the environment.

The Alberta EIA process is implemented in accordance with the Alberta EIA Guidelines and administered by the Alberta Department of Environment. Most major resource developments proposed in Alberta are subject to this requirement. Major thermal and hydro generation projects require an EIA, and proponents of smaller projects must submit the environmental information necessary for the required approvals. In preparing an EIA, the proponent must consult with the public and provide opportunities for the public to participate in the preparation and review of the EIA.

Energy projects require the approval of the Alberta Energy Resources Conservation Board (ERCB) and Alberta Environment. Consequently, Alberta Environment and the ERCB coordinate their respective information requirements and reviews of energy projects. EIAs on energy projects are filed with Alberta Environment and the ERCB as part of the application to the ERCB. The ERCB may require a public hearing to be held for a project. After the ERCB makes its decision, Alberta Environment issues detailed environmental permits and licences.

Following three years of extensive public consultation, Alberta's Environmental Protection and Enhancement Act was passed and proclaimed on September 1, 1993. Highlights of the legislation and the new regulations include provisions to establish a legislated environmental impact assessment process, increase public consultation and participation, and allow more public access to information on proposed developments which may impact the environment.

Saskatchewan

The Environment Assessment Act of 1980 requires environmental impact assessments to be completed for major development projects.

Exemptions may be granted by Cabinet only in cases of emergency.

The province's environmental impact assessment and review process is administered by the Saskatchewan Department of Environment and Resources Management (formerly Department of Environment and Public Safety), and projects may proceed only with the approval of the Minister. Proposals are screened by the department to determine whether the Act applies to a project and, if so, the nature and scope of the EIA. If it is determined that an EIA is not required, the project may proceed subject to all other statutory requirements.

Where an EIA is required, proponents are encouraged to undertake a public participation program as early as possible so that public comments and recommendations may be considered during the preparation of the Environmental Impact Statement (EIS). Further safeguards are built into the process, such as a minimum 30-day public review of the EIS and the power given to the Minister to require a public information meeting to be conducted and/or appoint a board of inquiry. The final decision to approve (with or without conditions) or to refuse the proposed development rests with the Minister. The government intends to reform the current environmental review process in the coming year.

Manitoba

The Manitoba Environment Act of 1988 replaces the former Clean Environment Act of 1968 and the Environmental Assessment and Review Process, adopted as provincial Cabinet policy in 1975.

The Act ensures that any person or organization undertaking a development specified in the regulations is required to file a Proposal with the Department of Environment at an early stage in the planning schedule. Other developments of environmental consequence are governed by regulations setting standards for environmental protection.

Developments are classified according to their potential environmental impact. Class 1 developments are any activities discharging pollutants. Class 2 developments are any activities with significant environmental impact caused by factors in addition to pollution, such as transportation and transmission facilities. Class 3 developments involve large-scale projects such as major hydroelectric developments.

Every submission for a development must be filed at a public registry. Once a proposal is filed, the Department of Environment is required to invite publicly written comments on the proposal. For more complex proposals, study guidelines are developed to assist proponents in preparing environmental assessments. Both the guidelines and the completed assessment are made available to the public for review.

Public meetings hosted by the proponent or public hearings by the Manitoba Clean Environment Commission, or both, may be held as part of the assessment and review process. The Commission's role is to provide advice and recommendations to the Minister and to develop and maintain public participation in environmental matters.

The final product of the process is an environmental licence with terms and conditions specific to the proposal. Alternatively, a licence to proceed could be refused on the grounds of unacceptable environmental damage.

Ontario

The Minister of the Environment is responsible for the administration of the Environmental Assessment Act, which promotes improved planning by involving government ministries and

agencies and the public in the environmental assessment, planning and approval process. (The environmental process in Ontario is also subject to the terms of the Consolidated Hearings Act, 1981. Details of the Consolidated Hearings Act may be obtained from *Environmental Assessment in Canada*[3], or from the October 1987 issue of *Canadian Environmental Law Reports.*[4] The environmental assessment process in Ontario is currently being reviewed by the government. Amendments to the Environmental Assessment Act are expected to be proposed in the very near future.

The Environment Minister may, with the approval of Cabinet, exempt proponents from the application of the Environmental Assessment Act, which currently applies to the activities of provincial ministries, municipalities and conservation authorities. Only those projects of the private sector designated by regulation are subject to the Act. Proponents planning a project must determine if the Act applies; where it does not apply; or where an exemption has been granted, the activity may proceed. If the Act applies, the proponent must prepare an Environmental Assessment (EA), which is reviewed by the Ministry of Environment and other interested provincial and federal government organizations.

The Ministry subsequently prepares a Government Review which, together with the EA, is released for a minimum 30-day public review. A hearing of the Environmental Assessment Board may then be requested by the reviewers, the public or the proponent. The Minister -- with the concurrence of Cabinet -- will make a decision whether to accept the EA, and whether to approve the undertaking, with or without conditions. The Minister may refer the decision to accept the EA, or the decision to approve the undertaking, or both, to a Board hearing. When the Minister decides to refer the matter to a Board hearing, the Board must give reasonable notice of the hearing, which is open to the public. The Minister or Cabinet has 28 days to make any amendments to the Board's decision; if no amendments are made within this period, the Board's decision becomes binding.

Quebec

In Quebec, the process of environmental assessment varies depending on whether a project is in the south of the province or in a territory that is the subject of agreements with native people.

The 1972 Environment Quality Act was amended significantly in 1978 to include an environmental impact assessment and review procedure. By regulation, this procedure applies essentially to projects in the south of the province. When a project is subject to the procedure, the proponent must submit an EIA to the Department of the Environment for an admissibility analysis and an evaluation of the environmental acceptability of the project. All projects are subject to a public consultation period, during which any citizen may ask the Minister of the Environment to hold a public hearing. Citizens can thus voice their views before the project is referred to Cabinet for acceptance or refusal. A new Act modifying the environmental evaluation process was passed in 1992. It will come into effect as soon as the government adopts secondary legislation.

In the northern Quebec territories, the provincial government has implemented two procedures to assess and review the environmental and social impacts of a given project. The first procedure is applicable to the James Bay region (between the 49th and 55th parallels). A feature of this procedure is the use of committees on which native people are always represented.

3 William J. Couch, Ph.D., op. cit.

4 *Canadian Environmental Law Reports*, New Series, Vol. 1, Part 6, October 1987.

These committees advise the Minister of the Environment throughout the various stages of the authorization process. North of the 55th parallel, the Kativik Environmental Quality Commission is in charge of reviewing the impact assessment study and has decision-making authority. These procedures, which were incorporated into the Environment Quality Act, stemmed from the James Bay and Northern Quebec Agreement (1975) and the Northeastern Quebec Agreement (1978).

New Brunswick

New Brunswick's Regulation on Environmental Impact Assessment came into effect in July 1987, to provide a legislative framework for environmental planning, including opportunities for public involvement. The Regulation, which replaced the province's 1975 Policy on Environmental Assessment, is designed to identify the environmental impacts associated with development proposals, before their implementation.

Under the Regulation, individuals, companies or public agencies proposing certain types of projects (for example, all electric power generating facilities with a production rating of three MW or more, and all electric power transmission lines exceeding sixty-nine kV in capacity or five km in length) are required to register information about the project with the Minister of Environment, at an early stage in the planning cycle. The Minister then screens the proposal to determine whether it is likely to have significant environmental impacts, including socioeconomic and biophysical effects.
If it appears that the project's impacts are likely to be significant, the Minister will inform the proponent that an EIA is required, and staff from the Department of Environment will work with the proponent in preparing initial draft guidelines for the EIA Study. A Review Committee, consisting of technical specialists from government agencies potentially affected by the proposal, is appointed by the Minister to formulate draft guidelines for the Study. These draft guidelines, which identify the important environmental issues to be addressed, must then be issued by the Minister for public comment, and any interested party may provide written comments to the Minister.

The principal objective of the EIA Study is to predict the project's impacts, should it proceed. Information gathered during the study is compiled in a draft Environmental Impact Assessment Report, which is then carefully examined by the Review Committee. If, on the advice of the Committee, the Minister is satisfied that the report adequately addresses all aspects of the guidelines, a second and more comprehensive opportunity for public involvement begins. A summary of the report, comments of the Review Committee, and full copies of the final report are released for public review and comment.

A public meeting to discuss the EIA takes place. Thereafter, the Minister reviews the study and public comments, and then recommends to the Lieutenant-Governor in Council whether or not the project should proceed.

A proposal to revise the current environmental impact assessment regulation has been prepared by the Department of Environment and has received comments for input from other government departments and the public. A new bill is likely to be recommended to the New Brunswick Legislature in the spring of 1995.

Nova Scotia

The current legal basis for environmental impact assessment in Nova Scotia is the Environmental Assessment Act. The Nova Scotia Department of the Environment (NSDOE), in consultation with other government agencies, is responsible for screening all projects submitted and advising the Minister on those that may have a significant

and adverse environmental impact. After reviewing NSDOE's advice, as well as any public concern expressed, the Minister decides whether a project requires an Environmental Assessment (EA) Report. Where it is decided one is required, the proponent prepares a draft Report in response to guidelines and submits it to NSDOE. The department, other interested provincial and federal agencies, and the public, review the EA Report. NSDOE then recommends to the Minister whether the project should be approved, with or without conditions, or refused.

The public is invited to participate in the review process by providing comments when a project is submitted to the NSDOE, when study guidelines are issued, and when the EA Report is released. The Minister, taking into consideration NSDOE's recommendations and the views of the public, decides whether the project should proceed and, if so, under what conditions.

The Department of Environment is now undertaking comprehensive legislative review and consolidation of all environmental acts (14) and regulations (44). A proposed new Nova Scotia Environment Act was released for public consultation in October 1993, and a report on the results of public consultation was published in June 1994. This new Act will be introduced to the Legislature in the fall of 1994.

Prince Edward Island

The Environmental Protection Act of 1988 provides the overall legal authority for the environmental assessment process. It requires that any person who wishes to initiate a project must file a written proposal with the Department of Environmental Resources (formerly Department of Environment) and obtain written approval from the Minister to proceed.

With respect to utilities, the process is set out in the Electric Power and Telephone Act, which authorizes the Public Utilities Commission to issue project-specific guidelines to the proponent for the preparation of an EIS, if it believes that the project may adversely affect the environment. A copy of the EIS is then sent by the Commission to the Executive Council for its consideration. The Council may make a decision on the evidence available, or it may determine that the public interest requires public hearings to be held in the locality affected by the project. After the public hearings, the Commission examines the evidence and issues its findings to the Executive Council.

Newfoundland

The province's environmental assessment process operates under the authority of the Environmental Assessment Act of 1980, which is administered by the Department of Environment and Lands.

Any project that may have a significant adverse environmental impact must be registered with the Minister of Environment and Lands. After public and interdepartmental reviews of the registration document, the Minister, on the advice of the department, decides whether or not an EIS is required. If an EIS is not required, the project may proceed subject to other relevant acts or regulations.

Where the Minister, on the advice of the Department, decides that an EIS may be required, an Environmental Preview Report (EPR) can be ordered. The EPR is prepared by the proponent and is available for public review and comment. Upon examination of the EPR, the Minister decides whether an EIS is required. If one is not required, the project may proceed subject to other relevant acts or regulations.

Where an EIS is required, it is prepared by the proponent; the Minister then makes it available

for public review and comment. Should strong public interest be expressed, the Minister may recommend to Cabinet that an Environmental Assessment Board be appointed to conduct public hearings. The Minister makes the Board's report public, delivers copies to Cabinet, and subsequently recommends to Cabinet whether the project should be permitted to proceed, with or without conditions, or whether permission should be refused.

Like some of the other provinces, the Government of Newfoundland is now carrying out an internal study on its environmental review process. The government intends to modify or change the existing acts or regulations during the coming year.

Table 4.1 is on the following page.

Tables & Figures

Table 4.1
Sulphur Oxide Emission Reduction Targets, 1994

Province	Base Case (tonnes)	Reductions (tonnes)	% Objectives	Emissions (tonnes)
Manitoba	738 000	188 000	25.5	550 000
Ontario	2 194 000	1 529 000	69.7	665 000
Quebec	1 085 000	485 000	44.7	600 000
New Brunswick	215 000	30 000	14.0	185 000
P.E.I.	6 000	1 000	16.7	5 000
Nova Scotia	219 000	15 000	6.8	204 000
Newfoundland	59 000	14 000	23.7	45 000
Total	4 516 000	2 262 000	50.0	2 254 000

Source: Natural Resources Canada

Electricity Consumption

Electricity and Primary and Secondary Energy

Electricity constitutes a significant market share of Canada's primary and secondary energy consumption. The contribution of electricity to total primary energy consumption[1] has steadily increased from 14 per cent in 1960 to 32 per cent in 1993, as shown in Figure 5.1. In terms of volume, primary energy consumption delivered in the form of electricity increased from 463 PJ in 1960 to 2840 PJ in 1993, an average annual growth of 5.6 per cent. This is more than double the average annual growth of non-electric primary energy consumption of 2.3 per cent registered for the same period. (Since 1990, the International Energy Agency (IEA) has agreed that hydro should be converted at 3.6 rather than 10.8 megajoules per kilowatt hour for the primary energy form).

Electricity constitutes a much smaller market share of secondary energy consumption[1] than primary energy consumption because of losses. Figure 5.2 indicates that electricity's share of Canadian secondary energy consumption was 11 per cent in 1960, and 25 per cent in 1993. The consumption growth rate for electricity was estimated to be 5.3 per cent during the period 1960-93, compared with non-electric secondary energy consumption of 2.1 per cent.

Total Electricity Consumption

In planning an electrical system, total electricity consumption (demand) must be determined first, followed by what type of energy and capacity mix is required to meet this demand. Total electricity consumption in a given country, region, or area normally includes generation by electric utilities, generation by industrial establishments, and net imports (imports minus exports).

Canada's total electricity consumption has experienced two distinct periods over the past 33 years: the first period was one of high growth from 1960 to 1974, followed by a period of low growth from 1975 to 1993. The abrupt change coincided with the first oil crisis of 1973-74, following which consumption growth rates in the ten provinces and two territories shrunk significantly. This dramatic reduction in electricity consumption growth was mainly attributed to reduced economic growth, high energy prices and energy conservation efforts. As indicated in Table 5.1, average annual growth rate of Canadian electricity consumption during the period 1960-74 was 6.6 per cent, compared with only 3.4 per cent for the period 1975-93.

In 1993, Canadian electricity consumption rose by only 1.5 per cent due to slow economic growth. The real Gross Domestic Product grew 2.2 per cent as the economy recovered from a recession which began in 1990. Energy conservation resulting from the implementation of demand-side management was another factor contributing to low domestic electricity consumption.

Ontario is the only province that has experienced consecutive negative electricity demand growth since 1990. This occurred largely because of the economic recession, mild weather, energy conservation efforts in the province, and rate increases.

Although its market share has been declining, the industrial sector is still the major user of electricity in Canada. Of the total electricity consumed in 1993, it is estimated that about 42 per cent was consumed in the industrial

[1] *For definition, please see appendix on* ***Definitions and Abbreviations.***

sector, 28 per cent in the residential sector, 23 per cent in the commercial sector, and 7 per cent in transmission and distribution losses.

Since 1960, commercial sector energy consumption growth has been remarkable, averaging 6.9 per cent annually, compared with 5.9 per cent for the residential sector, and only 3.4 per cent for the industrial sector. Transmission and distribution losses have been reduced steadily since 1960 partly due to improvements of transmission technology.

Table 5.3 shows electricity flows in Canada. Quebec was the largest producing and consuming province, accounting for 30 per cent of Canada's total production and about 35 per cent of total consumption. Ontario was second with 27 per cent of production share and 28 per cent of consumption share. British Columbia was in the third place, with 11 per cent in production and 12 per cent in consumption shares.

Per Capita Electricity Consumption

As in the case of total consumption, per capita electricity consumption in Canada exhibited high and low growth patterns before and after the oil crisis of 1973-74. For the period 1960-93, Saskatchewan had the highest annual per capita growth in electricity consumption, averaging 6.8 per cent, followed by Prince Edward Island with 6.5 per cent, and Alberta with 5.9 per cent. High per capita electricity consumption in Saskatchewan was due to a slow population growth. During the past 33 years, Saskatchewan's growth rate was 0.3 per cent compared to the national average of 1.4%. In fact, Saskatchewan's population has been declining since 1988.

In 1993, Quebec was the largest electricity user in Canada with 23 652 kWh per person, about 40 per cent higher than the national average. This high electricity use is attributed to relatively low electricity prices and a high percentage of households (about 69 per cent) using electricity for space heating. In comparison, Prince Edward Island was the smallest electricity user in Canada with 6106 kWh (only about 36 per cent of the national average). Prince Edward Island has the highest electricity prices of the ten provinces and does not use electricity for household space heating. A great majority of households in Prince Edward Island use oil for space heating.

Household Characteristics and Facilities

As was pointed out earlier, electricity consumption in the residential sector has steadily increased, from a 19 per cent market share in 1960 to 28 per cent in 1993. In addition to economic factors, changes in household characteristics and household facilities and equipment also have considerable impact on residential electricity consumption. Table 5.5 summarizes household characteristics and facilities by province for 1993.

During the past 18 years, the number of households in Canada has increased from 6.9 million in 1976 to 10.2 million in 1993, a net increase of 3.3 million. However, the average number of persons per household has declined from 3.15 to 2.62 over the same period.

The use of electricity for space heating, mainly in the provinces of Quebec and New Brunswick, has steadily increased from 13 per cent of total households in 1976 to 34 per cent by 1993; the number of air conditioners from 13 per cent to 26 per cent; and automatic dishwashers from 19 per cent to 45 per cent. The use of electric washing machines also increased slightly over the same period, from 76 per cent to 79 per cent, while the use of electric clothes dryers increased significantly from 51 per cent to

75 per cent. By the end of 1993, households equipped with refrigerators and colour TV sets in Canada reached 100 and 98 per cent respectively.

Economic Growth and Electricity Consumption

Electricity consumption is affected by many factors: economic activity, demographic variables, electricity prices, other energy prices, conservation, policy changes, technological changes and weather. However, aggregate economic activity [as measured by the Gross Domestic Product (GDP)] is the most important variable. The historical relationship between per capita GDP and per capita electricity consumption is shown in Figure 5.4. Although the historical relationship between national economic growth and electricity consumption was dislocated between 1979 and 1983 (because of the second oil crisis of 1979 and the 1982 recession - the worst recession since WW II), it has reappeared since 1984.

Peak Demand

Peak demand is the annual maximum average kilowatt load of one hour duration within an electrical system. All electrical systems in Canada are peak in the winter. Table 5.8 reports the day in the winter which had the highest one-hour demand for each province over the 1993-94 period. For Canada as a whole, peak demand grew from 17 264 MW in 1960 to 86 040 MW in 1993 (Table 5.6), an average annual growth rate of 5.0 per cent. In comparison, total electricity consumption during the same period grew at an average of 4.6 per cent.

In 1993, peak demand increased by 4.5 per cent, which was mainly attributed to the exceptionally cold weather. (Prior to 1987, *Electric Power in Canada* reported peak demand for the calendar year. However, beginning in 1987, calendar-year peak was replaced by winter peak - November to February. This change was made in order to make our reporting period consistent with that of the utilities.)

Load Factor

Load factor is defined as the ratio of average demand to peak demand in any given period. More precisely, it is the energy demand in kilowatt hours divided by the product of the number of hours in the period, multiplied by the peak demand in kilowatt. (In a year-base, average demand equals annual energy consumption divided by 8760 hours per year.)

Table 5.7 shows that for the electric power industry in Canada as a whole, load factor has declined since 1960. This has occurred because peak demand has grown faster than energy demand (5.0 per cent compared with 4.6 per cent). In 1960, the industry load factor was 72.3 per cent, but by 1980 it had gradually reduced to 65.6 per cent. Since then, the load factor have varied around 65 per cent.

Electricity Intensities

Electricity intensity is defined as total electricity consumption per dollar of gross domestic product. Table 5.9 compares the intensity of electricity use in the economies of all ten provinces and two territories combined for the period 1976-93.

For Canada as a whole, electricity intensity increased significantly from 1976 to 1985, then declined slightly. Ontario, British Columbia and the two territories exhibited the same pattern.

However, electricity intensities for other provinces appear to be steadily increasing, especially in Alberta, Saskatchewan and Prince Edward Island. Newfoundland, New Brunswick and Quebec have consistently had electricity intensities of greater than one, implying that these provinces require more electricity to produce one dollar worth of Provincial Gross Domestic Product than other provinces.

Labour Productivity of Canada's Electric Utilities

To measure Canada's electric utility corporate performance, one of the best indicators is labour productivity, which is defined as total energy delivered per regular employee. Regular employees include full-time employees considered permanent and involved in electrical utility service.

As Table 5.10 indicates, labour productivity including exports has increased from 3.41 GWh per person in 1970 to 6.04 GWh per person in 1993, with an average annual growth rate of 2.5 per cent. If exports are excluded, the adjusted average annual growth rate is 2.3 per cent.

Labour productivity improved about 7.9 per cent (including exports) and 6.8 per cent (excluding exports) in 1993 as a result of increased energy deliveries of 3.0 per cent, accompanied by a 4.4 per cent reduction in regular employees.

Tables and figures referred to in this chapter are on the following pages.

Tables & Figures

Table 5.1
Electricity Consumption by Province

	Electricity Consumption (GWh)					Average Annual Growth Rate (per cent)			
	1960	1970	1980	1990	1993*	1960-74	1975-93	1960-93	1992-93
Nfld.	1 427	4 770	8 545	10 422	10 904	11.5	3.2	6.4	1.9
P.E.I.	79	250	518	753	806	11.9	3.7	7.3	4.4
N.S.	1 733	3 706	6 814	9 678	9 919	8.7	3.1	5.4	0.1
N.B.	1 684	4 221	8 838	13 173	13 873	10.1	4.1	6.6	-0.1
Que.	44 002	69 730	118 254	157 308	170 153	5.4	3.6	4.2	3.4
Ont.	37 157	69 488	106 509	142 818	137 483	6.4	2.4	4.0	-1.4
Man.	4 021	8 601	13 927	17 450	18 642	7.9	2.5	4.8	1.4
Sask.	2 124	5 402	9 827	13 589	15 279	9.2	4.3	6.2	4.9
Alta.	3 472	9 880	23 172	42 041	46 960	10.7	6.5	8.2	2.3
B.C.	13 413	25 761	42 789	57 206	58 672	6.9	3.3	4.6	2.3
Yukon	89	220	381	485	335	9.3	-0.3	4.1	-30.2
N.W.T.	100	308	494	472	584	10.2	1.8	5.5	0.5
Canada	**109 304**	**202 337**	**340 068**	**465 395**	**483 610**	**6.6**	**3.4**	**4.6**	**1.5**

* Preliminary Data

Source: Electric Power Statistics, Volume II, Statistics Canada, catalogue 57-202

Table 5.2
Electricity Consumption in Canada by Sector

	Electricity Consumption (GWh)						Average Annual Growth Rate (per cent)	
	1960	1970	1980	1990	1992	1993*	1960-93	1992-93
Residential	20 397	43 431	92 440	137 001	137 442	136 937	5.9	-0.4
	(19)	(21)	(27)	(29)	(29)	(28)		
Commercial	12 632	44 068	75 912	110 057	107 872	111 754	6.9	4.5
	(12)	(22)	(21)	(24)	(23)	(23)		
Industrial	66 353	98 450	142 247	184 136	198 184	201 151	3.4	1.5
	(60)	(49)	(42)	(40)	(41)	(42)		
Line losses**	9 920	16 388	32 469	34 201	33 040	32 768	3.7	-0.8
	(9)	(8)	(10)	(7)	(7)	(7)		
Total	109 304	202 337	340 068	465 395	476 538	483 610	4.6	1.5
	(100)	(100)	(100)	(100)	(100)	(100)		

* Preliminary data.
** Losses during transmission, distribution and unallocated energy.
Figures in parentheses are percentage shares.

Source: Electric Power Statistics, Volume II, Statistics Canada, catalogue 57-202 and Natural Resources Canada

Table 5.3
Provincial Electricity Consumption and Generation, 1993

	Generation	Exports to Provinces	Exports to U.S.A.*	Imports from Provinces	Imports from U.S.A.	Consumption
	(GWh)					
Nfld.	40 846	29 942	0	0	0	10 904
P.E.I.	59	0	0	747	0	806
N.S.	9 714	41	0	248	0	9 919
N.B.	15 112	1 032	1 837	1 510	120	13 873
Que.	154 443	2 487	13 009	30 519	685	170 153
Ont.	140 708	555	7 157	1 897	2 590	137 483
Man.	27 121	2 240	7 359	924	196	18 642
Sask.	15 303	1 330	230	1 388	148	15 279
Alta.	48 277	2 088	0	769	2	46 961
B.C.	58 586	249	5 256	2 062	3 629	58 672
Yukon	335	0	0	0	0	335
N.W.T.	584	0	0	0	0	584
Canada	**511 088**	**40 064**	**34 848**	**40 064**	**7 370**	**483 610**

* Service exchange is included.

Source: Natural Resources Canada

Table 5.4
Per Capita Electricity Consumption by Province

	Per Capita Consumption (kWh/person)						Average Annual Growth Rate (per cent)	
	1960	1970	1980	1990	1992	1993	1960-93	1992-93
Nfld.	3 184	9 226	14 758	18 188	18 410	18 768	5.5	1.9
P.E.I.	765	2 273	4 177	5 748	5 893	6 106	6 5	3.6
N.S.	2 385	4 739	7 988	10 813	10 746	10 758	4 7	0.1
N.B.	2 864	6 732	14 850	18 245	18 535	18 497	5.8	-0.2
Que.	8 565	11 597	18 735	23 556	22 945	23 652	3.1	3.1
Ont.	6 086	9 203	12 422	14 648	13 080	12 843	2.3	-1.8
Man.	4 932	8 750	13 521	16 024	16 510	16 734	3.8	1.4
Sask.	1 750	5 741	10 131	13 630	14 512	15 248	6.8	5.1
Alta.	2 695	6 194	11 135	17 000	17 395	17 694	5.9	1.7
B.C.	8 386	12 124	16 220	18 259	16 493	16 678	2.1	1.1
Yukon	4 589	11 957	17 085	18 654	16 552	10 469	2.5	-36.8
N.W.T.	5 304	8 851	11 052	8 741	10 375	9 270	1.7	-10.7
Canada	**6 184**	**9 501**	**13 112**	**17 490**	**16 524**	**16 870**	**3.1**	**2.1**

Source: Electricity Branch, Natural Resources Canada.

Table 5.5
Household Characteristics and Facilities in Canada, 1993

	Canada	Nfld.	P.E.I.	N.S.	N.B.	Que.	Ont.	Man.	Sask.	Alta.	B.C.
Total number of households(1000)	10 247	182	47	336	256	2 688	3765	387	361	923	1 302
Average persons per household	2.6	3.1	2.7	2.6	2.8	2.5	2.7	2.7	2.6	2.7	2.5
Single dwellings* (%)	66	85	75	74	76	60	70	76	80	73	66
Electricity for space heating (%)	34	41	-	24	57	69	22	33	4	-	30
Air conditioners (%)	26	-	-	4	10	15	45	46	34	9	9
Electricity for cooking (%)	94	95	89	89	95	97	92	98	97	91	93
Microwave ovens (%)	79	72	77	80	82	76	80	80	85	85	78
Refrigerators (%)	100	100	98	99	100	100	100	100	100	100	100
Freezers (%)	59	78	68	63	68	48	58	73	80	70	58
Automatic dishwashers (%)	45	23	34	33	35	46	42	40	48	57	52
Electric washing machines (%)	79	91	85	80	88	85	75	77	86	80	74
Electric clothes dryers (%)	75	77	77	71	83	80	71	74	84	79	71
Colour TV sets (%)	98	97	98	97	98	98	98	97	98	98	97

* Including mobile homes.

Source: Household Facilities and Equipment, 1993, Statistics Canada, catalogue 64-202

Table 5.6
Peak Demand by Province

	Peak Demand (MW)						Average annual Growth Rate (per cent)	
	1960	1970	1980	1990	1992	1993*	1960-93	1992-93
Nfld.	245	763	1 538	1 848	1 826	1 907	6.5	4.4
P.E.I.	21	55	104	135	138	143	6.1	3.6
N.S.	356	814	1 197	1 825	1 821	1 922	5.2	5.5
N.B..	319	726	1 699	2 627	2 708	2 836	6.9	4.7
Que.	5 871	11 127	20 680	29 259	30 449	30 932	5.3	1.6
Ont.	6 391	12 048	17 767	23 752	23 027	25 246	4.1	9.6
Man.	772	1 565	2 681	3 524	3 401	3 564	4.7	4.8
Sask.	418	1 028	2 085	2 356	2 455	2 482	5.7	1.1
Alta.	714	1 894	3 879	6 509	6 758	6 874	7.3	1.7
B.C.	2 123	4 492	7 384	9 329	10 064	9 988	5.0	-0.8
Yukon	19	39	75	81	78	57	4.9	-26.9
N.W.T.	15	41	81	107	102	89	6.2	-12.7
Canada	17 264	34 592	59 170	81 352	82 330	86 040	5.0	4.5

* Preliminary Data

Source: Electric Power Statistics, Volume I, Statistics Canada, catalogue 57-204

Table 5.7
Load Factor by Province

	1960	1965	1970	1975	1980	1985	1990	1992	1993
					(per cent)				
Nfld.	66.5	72.6	71.4	68.7	65.3	64.5	64.4	66.9	65.3
P.E.I.	66.4	65.4	65.8	65.4	68.4	64.9	63.7	63.9	64.3
N.S.	59.5	66.4	62.7	58.4	59.3	62.0	60.5	62.1	58.9
N.B.	58.0	60.3	60.0	62.2	53.8	62.5	57.2	58.5	55.8
Que.	85.6	72.5	71.5	67.9	65.3	64.5	61.4	61.7	62.8
Ont.	66.4	65.4	65.8	65.4	68.4	64.9	68.6	69.1	62.2
Man.	59.5	66.4	62.7	58.4	59.3	62.0	56.5	61.7	60.6
Sask.	58.0	60.3	60.0	62.2	53.8	62.5	65.8	67.8	70.2
Alta.	55.5	57.1	59.6	64.2	68.2	72.3	73.7	77.5	78.0
B.C.	72.1	71.6	65.5	64.4	66.2	66.1	70.0	65.0	67.1
Yukon	53.5	77.8	64.4	60.9	58.0	54.3	68.4	63.0	67.1
N.W.T.	76.1	58.6	85.8	71.3	69.6	70.6	50.4	65.0	74.9
Canada	72.3	68.1	66.8	65.7	65.6	65.1	65.3	65.7	64.4

Source: Calculated from Tables 5.1 and 5.6

Table 5.8
Days of Peak Demand, Winter 1993-94

Province	Day
Newfoundland - Labrador	January 23
Newfoundland - Island	February 9
Prince Edward Island	December 20
Nova Scotia	January 19
New Brunswick	January 27
Quebec	January 27
Ontario	January 19
Manitoba	February 7
Saskatchewan	February 7
Alberta	January 5
British Columbia	November 22
Yukon	January 9
Northwest Territories	January 9

Source: Statistics Canada

Table 5.9
Electricity Intensity in Canada* (kWh/Can $ 1986)

	1976	1980	1985	1990	1991	1992	1993
Nfld.	1.33	1.46	1.55	1.52	1.54	1.58	1.60
P.E.I.	0.36	0.39	0.40	0.44	0.46	0.46	0.47
N.S.	0.65	0.66	0.64	0.72	0.74	0.75	0.74
N.B.	1.06	1.12	1.17	1.27	1.31	1.32	1.30
Que.	1.11	1.28	1.43	1.35	1.40	1.41	1.43
Ont.	0.72	0.75	0.71	0.72	0.74	0.71	0.69
Man.	0.87	0.99	0.94	0.95	1.01	1.02	1.02
Sask.	0.55	0.72	0.75	0.77	0.77	0.84	0.85
Alta.	0.34	0.47	0.61	0.68	0.72	0.74	0.72
B.C.	0.99	0.98	1.03	0.93	0.93	0.92	0.90
Yukon/ N.W.T	0.64	0.54	0.40	0.45	0.47	0.44	0.42
Canada	**0.84**	**0.89**	**0.97**	**0.93**	**0.95**	**0.95**	**0.94**

*Electricity intensity is defined as total electricity consumption per dollar of gross domestic product.

Source: Electricity Branch, Natural Resources Canada

Table 5.10
Labour Productivity of Canada's Electric Utilities

Year	Energy delivered including exports (GWh)	Domestic energy delivered (GWh)	Average regular employees	Labour productivity including exports (GWh/person)	Labour productivity excluding exports (GWh/person)
1970	148 526	145 114	43 597	3.41	3.33
1975	208 422	203 335	55 855	3.73	3.64
1980	292 822	264 972	65 504	4.47	4.05
1985	367 053	327 059	64 365	5.70	5.08
1986	381 292	344 681	64 483	5.91	5.35
1987	402 241	361 846	65 373	6.15	5.54
1988	408 585	381 262	66 226	6.17	5.76
1989	407 245	389 448	67 736	6.01	5.75
1990	401 188	386 234	70 988	5.65	5.44
1991	415 314	393 543	74 001	5.61	5.32
1992	421 383	396 395	75 219	5.60	5.27
1993	434 188	405 125	71 906	6.04	5.63

Source: 1993 Canadian Utility Composite Performance and Productivity Results, Canadian Electrical Association, June 1994, p. 29

Figure 5.1 Primary Energy Consumption in Canada

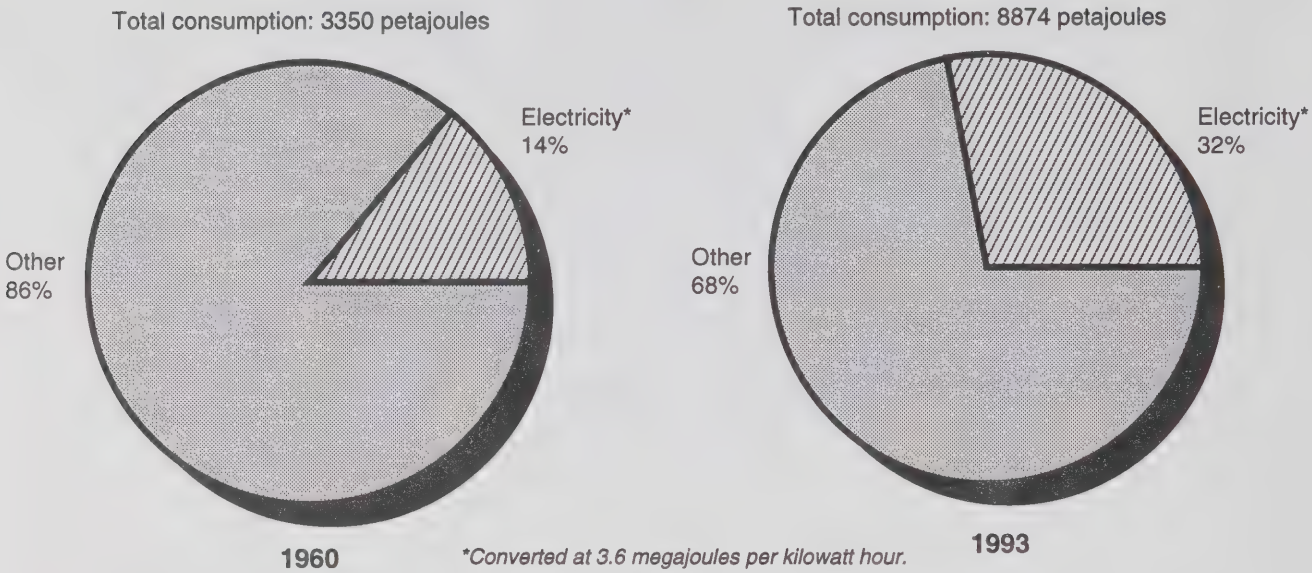


Figure 5.2 Secondary Energy Consumption in Canada

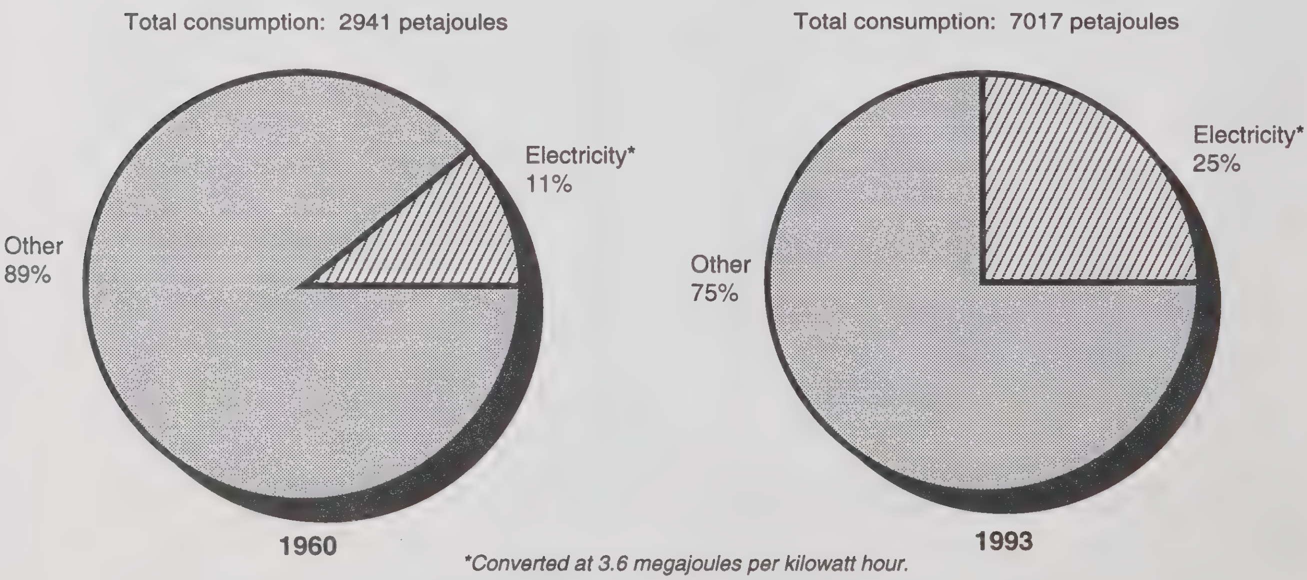


Figure 5.3
Electricity Generation, Consumption and Net Transfers, 1993 (GWh)

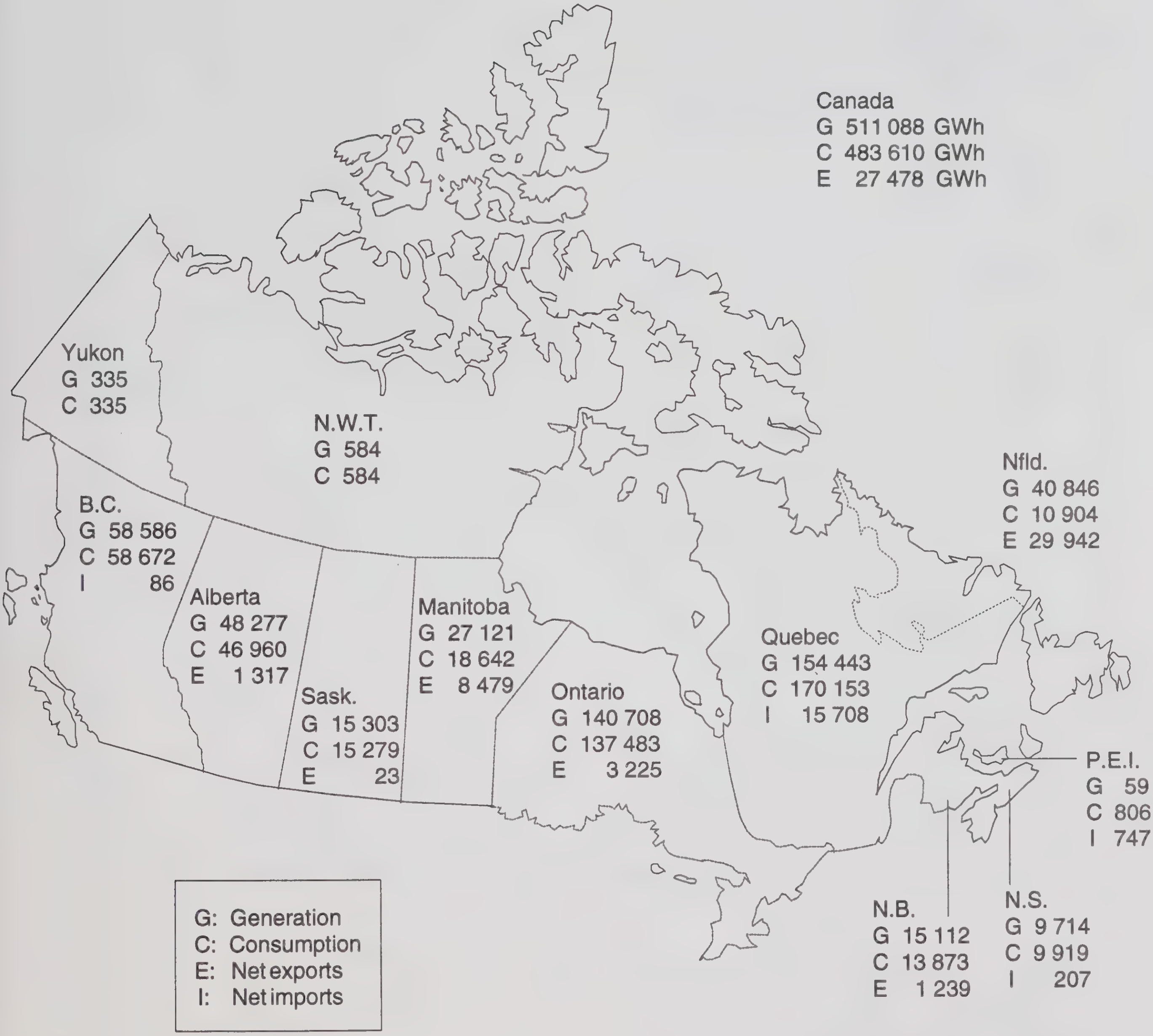
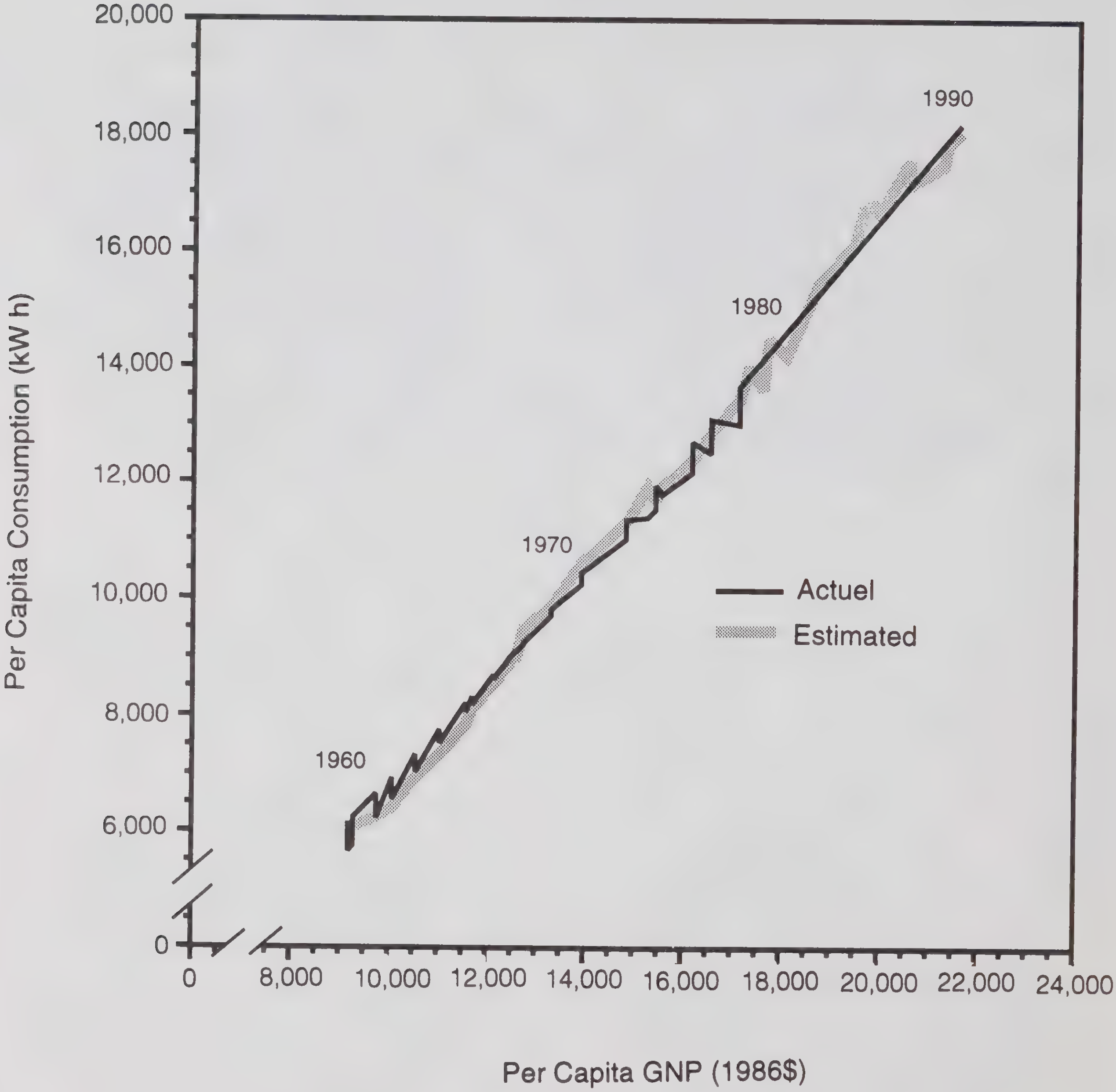


Figure 5.4 Historical Relationship between Electricity Demand and GDP, 1960-1993



Electricity Generation

Sources of Generation

Canada's electric power industry began in the 1880s with electricity generated by steam. In the beginning, electricity was used mainly for home and street lighting. In the late-1880s and 1890s, the invention of the electric motor dramatically changed the industry from one that mainly provided nighttime power for lighting to one that also provided power for transportation and industrial needs, 24 hours a day. Following this development, the use of hydroelectricity spread rapidly due to Canada's abundant water resources. In 1920, hydro accounted for more than 97 per cent of total electricity production in Canada. This percentage declined slightly to 95 per cent by 1950, and 92 per cent by the end of 1960. By 1993, hydro production had further declined to about 62 per cent (Table 6.1 and Figure 6.2).

Thermal generation, mainly from coal-fired stations, has been a part of Canada's generation mix since the beginning of the electric power industry. However, for many years its share of total production did not increase significantly because of its relatively high cost of production. This situation changed by the 1960s and 1970s, when most of Canada's economical hydro sites had been developed, and thermal generation became competitive.

Between 1950 and 1974, the growth rate of real fossil-fuel prices (coal, oil and natural gas) was negative -- a situation that led most electric utilities to build more thermal stations. As Table 6.1 indicates, thermal generation accounted for only 7 per cent of the total generated electricity in 1960. However, its production share jumped to 23 per cent by 1970, and reached a peak of 25 per cent in 1974. After the first oil crisis of 1973-74, fossil-fuel prices increased substantially, averaging more than 15 per cent during the 1975-85 period. As a result, the share of thermal production gradually declined to 22 per cent by 1980, and 20 per cent by 1985. With the collapse of oil prices in 1986, thermal generation once again became economical. As a result, thermal production's share rose to 22 per cent in 1990 and 1991, and up to 23 per cent in 1992. However, it was reduced to 21 per cent in 1993 attributing to the reduction of coal-fired generation because of environmental concerns.

The production of nuclear power began in Canada in 1962 when the 25-MW Rolphton station went into operation. In 1968, commercial operation started at the 220-MW Douglas Point station in Ontario, owned by Atomic Energy of Canada Ltd. During the 1970s, nuclear production emerged as an important source of electricity in Canada, and by 1975 nuclear generation accounted for more than 4 per cent of total electricity production. Most of the nuclear generation came from the first four Pickering stations in Ontario, which were completed between 1971-73. By 1980, the nuclear production share increased to about 10 per cent of Canada's total, with the completion of four of Ontario's Bruce stations.

By 1985, nuclear generation accounted for 13 per cent of Canada's total generated electricity. Between 1980 and 1985, seven nuclear stations were brought into service: Gentilly 2 in Quebec; Point Lepreau in New Brunswick; Pickering stations 5, 6 and 7, and Bruce stations 5 and 6, all located in Ontario. From 1986 to 1990, the nuclear generation share had increased to about 15 per cent with the commissioning of Pickering 8, Bruce 7 and 8, and Darlington 2, all of which went into operation in 1986, 1987, and 1990.

By 1993, nuclear generation's share increased to 17 per cent of total electricity generated in Canada due to the completion of the remaining three units of the Darlington Nuclear Station in 1992 and 1993.

To date, tidal power has played an insignificant role in electricity generation in Canada. However, it is worth noting that the 20-MW Annapolis tidal power plant in Nova Scotia, which began operation in 1984, is the first of its kind in North America. As compared to conventional hydro plants, this plant requires higher maintenance levels because of salt water exposure. However, considering greater maintenance levels, the plant has operated without any major difficulties since 1984.

Hydroelectric Power Development

Canada's rapid development of hydroelectric power in the past was mainly attributed to two factors: abundant water resources and the nationalization of private provincial electric utilities. The former provided the least-cost energy production, and the latter enabled the provincial government to use the public enterprise as an instrument to serve government industrial policy and other objectives.

In the first half of the century, the influence of government objectives on the structure of the industry was mainly focusing on the level and structure of prices and the need for universal service - the types of concerns traditionally addressed through government control over monopolies. It was in this period that Ontario Hydro (1906), Hydro-Québec (1944), Manitoba Hydro (1949), and British Columbia Power Commission (1946) were created.

Since 1950, electric utilities have come to be seen in a broader context, especially for those provinces endowed with hydroelectric power resources. Given the amount and importance of their capital expenditures to provincial economies, it was recognized that hydroelectric power development could serve such policy objectives as job creation, industrial development, and macro-economic stabilization. During this more recent period, nationalizations occurred that led to a major expansion of the publicly owned electric utilities in British Columbia and Quebec.

During the 1960s, the provincial government assumed a major role in promoting the modernization of Quebec society and increased francophone control over the provincial economy. Government enterprise was one of the main instruments used to achieve those objectives.

The nationalization of the private electric utilities in the province was among the more dramatic initiatives taken during this period. While Hydro-Québec had been established since 1944, in the early 1960s over half the electric power in the province was still being provided by investor-owned firms. The nationalization that occurred in 1963 was in part justified by the need to integrate the system and coordinate investment. All major hydro projects (James Bay Phase I and Manic) in Quebec were developed after 1963 in coordination with industrial development and increased employment.

The same is true for British Columbia and Manitoba. British Columbia Hydro & Power Authority (B.C. Hydro) was incorporated in 1962 by merging B.C. Power Commission and B.C. Electric Limited which was nationalized in 1961. B.C. Hydro is a Crown corporation providing electrical service throughout the province, with the exception of the south interior, which is served by the West Kootenay Power and Light Company Limited. The most important hydro projects in British Columbia, Gordon M. Shrum, Revelstoke, and Mica, were all built after 1962 to serve the provincial government's policy purposes.

Manitoba Hydro's mandate under the 1970 *Manitoba Hydro Act* is to provide adequate power supply to meet the needs of the province and to promote economy and efficiency in the generation, distribution, supply, and use of

power. With these government policy objectives, two major hydro projects, Kettle Rapide and Long Spruce, were commissioned in 1970 and 1977, respectively.

Electricity Generation in 1993

Electricity generation increased by 1.9 per cent in 1993, which is much greater than 1.5 per cent of the domestic electricity demand. The increase is mainly attributed to a greater number of exports to the United States and stronger domestic demand in Quebec and Saskatchewan. Of the total electricity generated in 1993, 476 240 GWh was for use in Canada and the remaining 34 848 GWh was exported. The sources of generation are given in Table 6.1, and the major generating stations in each province are shown in Figure 6.1.

Between 1960 and 1993, hydro production dropped from 92 per cent to 62 per cent, as shown in Figure 6.2. Natural gas production also decreased (from 4 per cent in 1960 to 2 per cent in 1993), while oil increased (from 1 per cent to 2 per cent over the same period). With the first oil crisis of 1973-74, electric utilities were discouraged from using natural gas and oil for baseload electricity generation. However, as noted above, the collapse of oil prices in 1986 has made electricity generation from oil more economical.

Nuclear's share of production had the largest gain, moving from zero in 1960 to about 17 per cent by 1993; coal production increased from 3 per cent to 15 per cent over the same period. These increases have occurred at the expense of hydro. With the relatively cheap fuel prices of uranium and coal and the development of most of the country's economical hydro sites, hydro's share of production has declined significantly since 1960.

Electrical energy production by fuel type by province in 1993 is reported in Table 6.2. In Newfoundland, Quebec, Manitoba, and British Columbia, hydro generation accounted for more than 96 per cent of the total. In Alberta, about 82 per cent of total generation came from coal. Coal generation was also important in Saskatchewan and Nova Scotia, at 68 per cent and 65 per cent respectively. In Ontario, coal, nuclear and hydro production are well balanced, while in New Brunswick, total generation is a mix of oil, nuclear, hydro and coal.

Ontario, Quebec and New Brunswick are the only three provinces that produce nuclear energy in Canada. In 1993, nuclear generation accounted for 56 per cent of Ontario's total electricity generation, 35 per cent of New Brunswick's, and 3 per cent of Quebec's. Electricity generation from natural gas occurs mainly in industries that generate power for their own use. In all provinces except Newfoundland, Nova Scotia and New Brunswick, oil is used mainly for peaking purposes.

Generation by Province

Table 6.3 shows electricity generation by province during the period 1960-93, and generation growth rates for 1993 over 1992 and the period 1960-93. Newfoundland had the greatest production growth during the period 1960-93, with an average growth rate of 10.5 per cent. This was due mainly to the completion of the Churchill Falls hydro station (5429 MW) in Labrador in 1974. Over 90 per cent of the electricity produced at Churchill Falls flows into Quebec under a contract that ends in the year 2041.

Electricity generation fluctuated significantly in Prince Edward Island during the period 1960-93. The province's electrical generating plants are relatively small, fuelled by oil, and are

consequently expensive to operate. In 1977, an interprovincial interconnection was completed, allowing P.E.I. to purchase electrical energy from New Brunswick. In addition, in 1981, P.E.I. purchased a 10 per cent ownership interest in the 200-MW coal/oil-fired plant at Dalhousie, New Brunswick. The interconnection and joint ownership has enabled P.E.I. to reduce the amount of generation from its own oil-fired stations.

In 1993, there was negative growth in electricity generation in British Columbia, Nova Scotia, New Brunswick and the Yukon (Table 6.3). The reduction of electricity generation in British Columbia was mainly due to the problem of water flows in the province.

Figure 6.3 presents electricity generation by region. Although Quebec has been the largest electricity producer in Canada since 1960, its share has declined from 44 per cent in 1960 to 30 per cent in 1993. Ontario was the second-largest producer, with 27 per cent in 1993, compared with 31 per cent in 1960. British Columbia has remained the third largest electricity producer over the period, generally providing 12 per cent of the total. Electricity generation growth rates for Newfoundland, Nova Scotia, New Brunswick, Manitoba, Saskatchewan and Alberta were all greater than those for Quebec, Ontario and British Columbia during 1960-93. This indicates that generation shares for the Atlantic and Prairie provinces are increasing at the expense of the top three provinces.

Fossil-Fuel Requirements

Because of the rapid expansion of coal-fired stations in the 1960s and 1970s, coal consumption increased about tenfold during the period 1960-75, and more than doubled in the following ten years. However, in recent years, environmental concerns have led to a more gradual increase in its use.

The use of natural gas and oil for electricity generation peaked in the mid-1970s and 1980, and then declined sharply. However, with the collapse of international oil prices in 1986, the situation reversed itself and it again became economical for electric utilities to use oil and natural gas for electricity generation (Tables 6.4 and 6.5). The use of uranium has increased dramatically since 1970 with the growth of nuclear capacity in Canada, particularly in Ontario.

In 1993, provinces west of Quebec continued to use Canadian oil, primarily light oil and diesel oil, in gas turbines or diesel plants. In the Yukon and Northwest territories, Canadian diesel oil was used to supply electricity to small remote communities. Oil used by the Atlantic region and Quebec was imported.

In 1993, about 62 per cent of the coal used for electricity generation in Ontario was imported from the United States, while the remainder came from western Canada. Coal used by Manitoba was purchased from Saskatchewan, while Alberta, Nova Scotia and New Brunswick used their own coal resources. Saskatchewan relied primarily on its own coal, but also purchased additional amounts from Alberta.

Heat Content of Fuel

According to Statistics Canada, heat content for the same type of fuel used for electricity generation varies from province to province. For instance, Canadian bituminous coal used in Nova Scotia has 27 295 kilojouls per kilogram, compared with 18 026 kilojouls per kilogram in Alberta. The same is true for light, heavy, and diesel fuel oil used for electricity generation. Table 6.6 summarizes heat content for various

fuels used in electricity generation in Canada in 1992.

Emissions from Electricity Generation

As shown in Table 6.1, 99 142 GWh of electricity came from conventional thermal sources, which accounted for about 21 per cent of total electricity generated in 1993. This amount of thermal generation required a considerable quantity of fossil fuels: 43 million tonnes of coal; 2.7 million cubic metres of oil; and 3459 million cubic metres of natural gas (Table 6.5). In 1993, about 86 per cent of the total coal consumption in Canada was used for electricity generation. The percentage shares for natural gas and oil are 4.4 per cent and 2.7 per cent, respectively.

The combustion of fossil fuels can produce carbon dioxide, sulphur dioxide, nitrous oxides, etc. Emissions from electricity generation in 1993 are presented in Table 6.7. In 1993, more than 49 per cent of the total sulphur dioxide emission in Canada came from the electric power industry, compared with 19 per cent of carbon dioxide and only 12 per cent of nitrous oxides emissions.

Tables and figures referred to in this chapter are on the following pages.

Tables & Figures

Table 6.1
Sources of Electricity Generation

Fuel Type	Electricity Generation 1960	1970	1980	1990	1992	1993	Average Annual Growth Rate 1960-93	1992-93
	(GWh)						(per cent)	
Hydro	105 883	156 709	251 217	292 810	312 099	319 069	3.4	2.2
Thermal	8 495	47 045	80 207	104 121	113 477	103 372	7.9	-0.1
Nuclear*	-	969	35 882	68 837	76 021	88 614	-	16.6
Tidal**	-	-	-	26	34	33	-	-2.9
Total	**114 378**	**204 723**	**367 306**	**465 744**	**501 631**	**511 088**	**4.6**	**1.9**

* Commercial operation started in 1968.
** Commercial operation started in 1984.

Source: Electric Power Statistics, Volume (II), Statistics Canada, catalogue 57-202, and Electric Power Statistics Monthly, Statistics Canada, catalogue 57-001

Table 6.2
Electrical Energy Production by Fuel Type, 1993

	Coal	Oil	Natural Gas	Nuclear	Hydro	Other	Total
			(GWh)				
Nfld.	0	1 649	0	0	39 197	0	40 846
P.E.I.*	0	59	0	0	0	0	59
N.S.	6 345	2 337	0	0	879	153	9 714
N.B.	1 291	5 232	0	5 323	3 024	242	15 112
Quebec	0	244	25	4 807	149 367	0	154 443
Ontario	18 015	2	3 337	78 484	40 290	580	140 708
Manitoba	185	12	20	0	26 863	41	27 121
Sask.	10 354	43	679	0	4 057	170	15 303
Alberta	39 351	0	5 809	0	1 829	1 288	48 277
B.C.	0	1 191	2 582	0	53 121	1 692	58 586
Yukon	0	48	0	0	287	0	335
N.W.T.	0	237	95	0	252	0	584
Canada	**75 541**	**11 054**	**12 547**	**88 614**	**319 166**	**4 166**	**511 088**

* PEI has 10 per cent ownership in New Brunswick's Dalhousie coal-fired station, unit 2.

Source: Natural Resources Canada

Table 6.3
Electricity Generation by Province

	Electricity Generation						Average Annual Growth Rate	
	1960	1970	1980	1990	1992	1993	1960-1993	1992-1993
	(GWh)						(%)	
Nfld.	1 512	4 854	46 374	36 585	36 681	40 846	10.5	11.4
P.E.I.	79	250	127	81	34	59	-0.9	73.5
N.S.	1 814	3 511	6 868	9 430	9 722	9 714	5.2	-0.1
N.B.	1 738	5 142	9 323	16 665	15 962	15 112	6.8	-5.3
Quebec	50 433	75 877	97 917	135 458	147 077	154 443	3.4	5.0
Ontario	35 815	63 857	110 283	129 343	138 518	140 708	4.2	1.6
Manitoba	3 742	8 449	19 468	20 149	26 763	27 121	6.2	1.3
Sask.	2 204	6 011	9 204	13 540	14 127	15 303	6.0	8.3
Alberta	3 443	10 035	23 451	42 874	47 520	48 277	8.3	1.6
B.C.	13 409	26 209	43 416	60 662	64 165	58 586	4.6	-8.7
Yukon	89	224	381	485	481	335	4.1	-30.4
N.W.T.	100	304	494	472	581	584	5.5	0.5
Canada	114 378	204 723	367 306	464 744	501 631	511 088	4.6	1.9

Source: Electric Power Statistics, Volume (II), Statistics Canada, catalogue 57-202

Table 6.4
Fuels Used to Generate Electricity in Canada

	1960	1965	1970	1975	1980	1985	1990	1992	1993
Coal (10^3) tonnes	1 674	7 004	13 786	16 567	27 785	39 456	41 822	43 641	42 791
Oil (10^3) cubic metres	328	871	1 869	2 309	2 867	1 391	3 888	3 453	2 686
Natural Gas (10^3) cubic metres	1 069	1 679	1 992	4 009	1 875	1223	3 084	2 631	3 459
Uranium (tonnes)	0	2	16	194	685	1 086	1 386	1 396	1 619

Source: Electric Power Statistics, Volume (II), Statistics Canada, catalogue 57-202, and Natural Resources Canada

Table 6.5
Fuels Used to Generate Electricity by Province, 1993*

	Coal (10^3 tonnes)	Oil (10^3 cubic metres)	Gas (10^6cubic metres)	Uranium (tonnes)
Nfld.	0	403	0	0
P.E.I.	34	25	0	0
N.S.	2 416	560	0	0
N.B.	526	1 318	0	100
Quebec	0	90	3	89
Ontario	6 962	31	271	1 430
Manitoba	75	0	1	0
Sask.	8 739	6	192	0
Alberta	24 039	6	2 463	0
B.C.	0	160	498	0
Yukon	0	13	0	0
N.W.T.	0	74	31	0
Canada	**42 791**	**2 686**	**3 459**	**1 619**

Note: 1 cubic metre oil = 6.3 barrels; 1 barrel of oil is defined as 5 800 000/BTU.
1 cubic metre gas = 35.5 cubic feet; 1 cubic foot of natural gas is defined as 1000 BTU.
1 tonne = 1000 kilograms; 1 gram of uranium is defined as 603 825 BTU.
* Preliminary Data

Source: Natural Resources Canada

Table 6.6
Heat Content in Canada, 1992

	Canadian Bituminous (kg)	Imported Bituminous (kg)	Sub-Bituminous (kg)	Lignite (kg)	Light Fuel Oil (litre)	Heavy Fuel Oil (litre)	Diesel (litre)	Natural Gas (m^3)	Uranium (g)
					(kilojouls)				
Nfld.	-	-	-	-	38 339	42 465	38 168	-	-
P.E.I.	-	-	-	-	-	41 497	35 726	-	-
N.S.	27 295	-	-	-	37 580	41 932	37 581	-	-
N.B.	26 901	-	-	-	38 740	41 409	39 133	-	576 200
Que.	-	-	-	-	41 381	41 608	38 680	-	632 000
Ont.	25 707	30 110	-	16 121	38 544	41 432	37 696	37 719	704 549
Man.	-	-	-	-	37 814	-	35 712	37 223	-
Sask.		-	-	16 282	37 100	-	38 000	36 523	-
Alta.	18 026	-	18 364	-	-	-	37 956	38 128	-
B.C.	-	-	-	-	-	-	36 162	38 499	-
Yukon	-	-	-	-	-	-	57 000	-	-
N.W.T.	-	-	-	-	-	-	37 001	-	-
Canada	**25 678**	**30 110**	**18 364**	**14 784**	**38 808**	**41 682**	**37 319**	**37 935**	**693 961**

Source: Electric Power Statistics Volume II, Statistics Canada, Catalogue 57-202

Table 6.7
Emissions from Electricity Generation, 1993

	SO_2 (1000 tonnes)	NO_x (1000 tonnes)	CO_2 (1000 tonnes)
Newfoundland	17	3	1 226
Prince Edward Island	1	0	73
Nova Scotia	168	26	8 549
New Brunswick	117	22	5 433
Quebec	3	0	0
Ontario	106	39	14 618
Manitoba	0	0	160
Saskatchewan	72	28	12 212
Alberta	106	89	47 219
British Columbia	0	1	1 406
Yukon	1	0	37
Northwest Territories	2	0	216
Electric Utilities' Total	593	208	91 143
Canada's Total Resulting from Energy Activities	1 212	1 692	472 279
Electric Utilities' Share (%)	49	12	19

Source: Electric Utilities and Natural Resources Canada

Figure 6.1 Major Generating Stations by Province, 1993 (MW)

Figure 6.2 Electricity Generation by Fuel Type

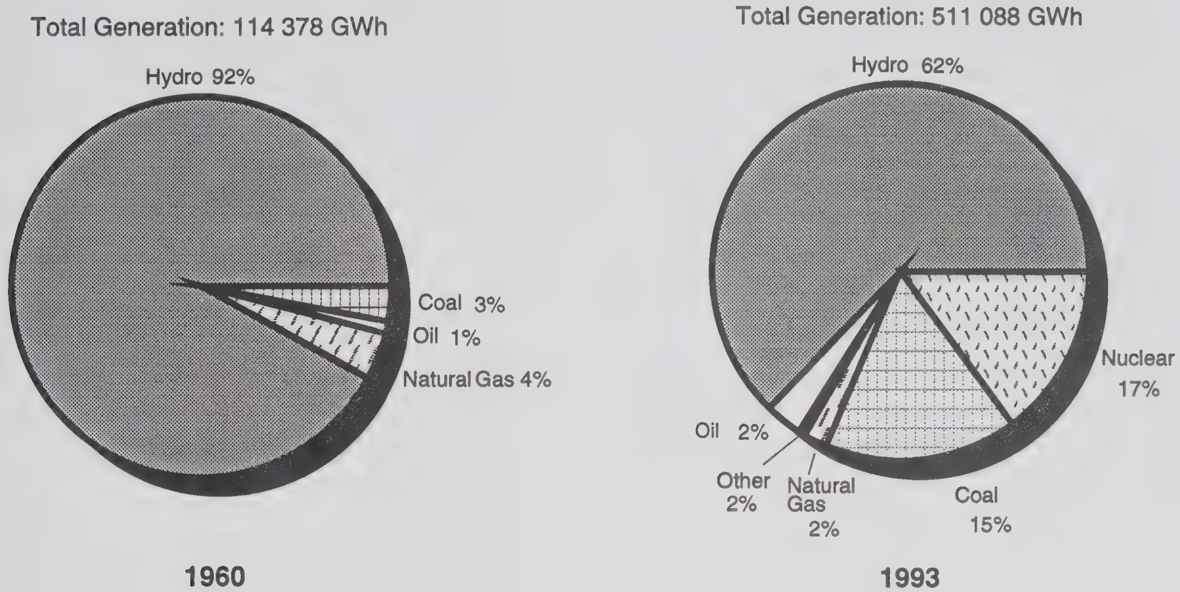
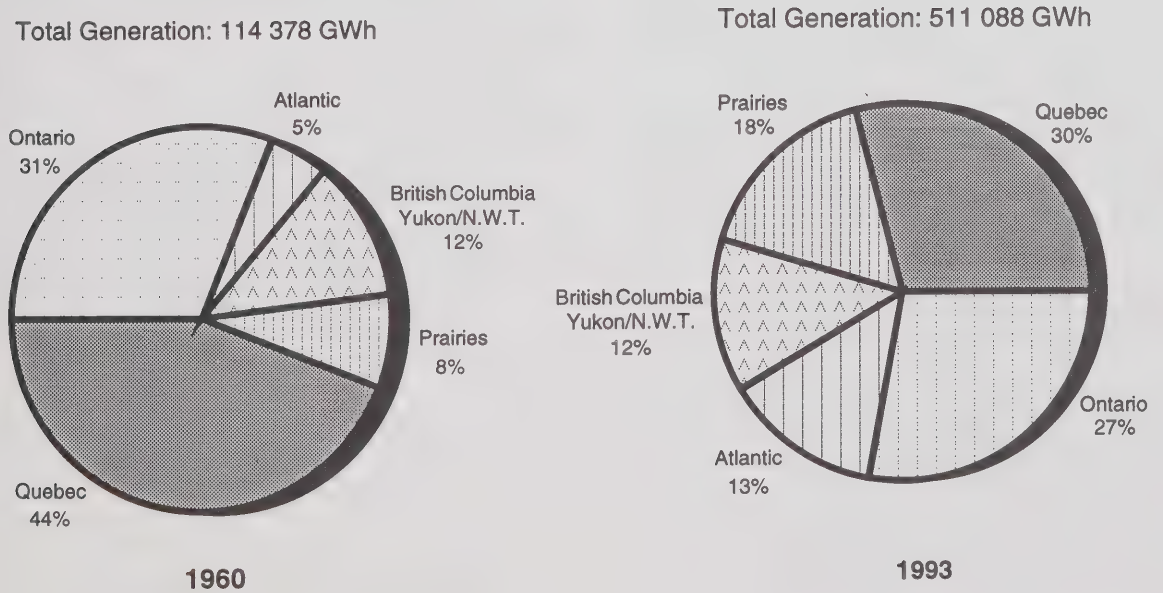


Figure 6.3 Electricity Generation by Region



Generating Capacity and Reserve

To meet load requirements, an electric power system must have sufficient installed generating capacity to satisfy the peak demand and the capability to supply the total energy requirements.

As discussed in Chapter 6, Canada's first electrical generating stations were thermal. As the demand for electricity grew and technology developed, hydroelectric power grew in importance, primarily for economic reasons. The use of hydroelectricity spread rapidly due to Canada's abundant water resources.

In 1920, hydro accounted for 86 per cent of total generating capacity, and by 1945, hydro's share of total installed capacity peaked at 94 per cent. Since then, the capacity share of hydro has declined gradually, reaching about 81 per cent by 1960, 58 per cent in 1980, and 56 per cent in 1993 (Table 7.1).

Several factors have contributed to the gradual reduction in the capacity share of hydro since the end of World War II. By 1945, many of Canada's economic hydro sites had been developed. Moreover, the growth rates of real fossil-fuel prices (coal, oil and natural gas) were negative between 1950 and 1974, a situation that led many utilities to construct thermal stations during this period. In addition, in the early 1960s, Canada began to develop nuclear energy as an alternative means of electricity generation.

Capacity Additions

There were only a few major capacity additions in 1993. This may be a result of energy conservation efforts and economic recession. New additions were about 3284 MW in 1993. Of this total, nuclear accounted for 1870 MW, followed by hydro 733 MW, coal 443 MW, oil 204 MW, and natural gas 34 MW.

Between October and December 1993, a 67 MW hydro generating unit went into service at Hydro-Québec's Manic 5 PA power station, as did two units (2x191 MW) at the Brisay hydro station and two units (2x137) at the La Forge 1 hydro station. In addition, the second unit of the 2x195 MW gas turbine at the Becancour station was also completed in October 1993.

The 443 MW unit at the Belledune coal-fired station, owned by New Brunswick Power was declared in-service in July 1993. This facility took three years to construct with a total cost of $635 million. Suppliers from seven countries brought the best available equipment and technology to this new coal-fired station.

Unit number 1 of Ontario Hydro's Darlington nuclear station (4x881 MW) went into service in November 1992; unit number 2 was completed earlier in October 1990; and the remaining two units were commissioned in February and July 1993. The gross installed capacity for each unit is 935 MW.

Capacity by Fuel Type and Province

Total installed capacity by fuel type and province for 1993 is given in Table 7.2. Although hydro's share of total installed capacity has declined, hydro is still the predominant source of electrical energy in Canada. In 1993, hydro's capacity share accounted for 56 per cent of total installed capacity, followed by coal 18 per cent, nuclear 14 per cent, oil 7 per cent, natural gas 4 per cent, and other (wood, flare gas, etc.) 1 per cent (Figure 7.1).

In the 1960s and early-1970s, Quebec had the largest installed capacity in Canada. Since the mid-1970s, however, Ontario's capacity has been the largest. In 1993, Ontario's installed capacity was 32 per cent of the Canadian total, followed by Quebec with 29 per cent and British

Columbia with 12 per cent. The combined total of these three provincial electrical systems accounted for 73 per cent of the total. Between 1960 and 1993, the Atlantic provinces had a major gain; their share increased from 5 per cent in 1960 to 13 per cent by 1993. This increase was due to the completion of the Churchill Falls project in Labrador in 1974, (Figure 7.2). Table 7.3 presents installed generating capacity by province for the period 1960-93.

Major Hydro Stations in Canada

Canada is a world leader in large hydro-station design, construction and operation. Table 7.4 lists Canada's ten largest hydro stations in 1993. Churchill Falls, Canada's largest hydro plant (5429 MW), ranked sixth among the world's hydro plants by present capacity. La Grande 2, situated in the James Bay region of Quebec, is Canada's second-largest hydro plant with 5328 MW and ranked seventh in the world. La Grande 4, also in Quebec, ranked seventeenth. British Columbia's Gordon M. Shrum hydro plant and Quebec's La Grande 3 ranked twenty-first and twenty-third among the world's largest hydro plants in 1993[1].

Among Canada's ten largest hydro plants, five are located in Quebec, mainly in the James Bay area, three in British Columbia, and one each in Newfoundland and Manitoba. These ten hydro stations have a total installed capacity of 26 427 MW, and in 1993 they accounted for about 42 per cent of Canada's total hydro capacity. Many smaller, but strategically important, hydro facilities are located throughout the country.

[1] *International Water Power and Dam Construction, Handbook 1993.*

Major Conventional Thermal (Fossil) Stations in Canada

Canada has significant long-term experience with a variety of thermal technologies of all sizes. In the 1950s and early-1960s, Canadian electric utilities built many steam plants with unit sizes from tens of MW to as large as 300 MW. Since then, advances in technology, stable fossil-fuel prices, and robust electricity demand growth have supported the development of larger steam plants. For example, Ontario Hydro's Lambton and Nanticoke coal-fired stations have unit sizes of 510 MW and 512 MW respectively, while the Lennox oil-fired station has four units of 550 MW. Electric utilities in Alberta and New Brunswick have constructed a number of coal-fired stations with unit sizes in the 400 MW range.

Table 7.5 lists Canada's ten largest thermal stations in 1993 Seven of the ten stations are using coal as input fuel, two oil and one natural gas. Five of the ten largest thermal stations are located in Ontario, where a large population results in significant economies of scale. Two of the stations are in Alberta, and there is one each in New Brunswick, Saskatchewan and British Columbia. Total combined capacity for these stations is 17 780 MW, which accounted for 53 per cent of Canada's total conventional thermal installed capacity in 1993.

Nuclear Power Stations in Canada

In the early-1960s, Canada started to develop nuclear energy as an alternative source for future energy demand. By 1993, Canada owned and operated 22 large CANDU reactors (500 MW and up), with a total installed net capacity of 15 391 MW. With the exceptions of Point Lepreau 1 in New Brunswick and Gentilly 2 in Quebec, they are all located in Ontario. Table 7.6 reports major nuclear power stations in Canada, in order of their commissioning date.

CANDU reactors (pressurized heavy water reactors) have been shown to be among the best nuclear reactors in the world in terms of cost-effectiveness, safety measures and output performance. Figure 7.3 indicates that among lifetime performance for five types of nuclear reactors (over 150 MW), the CANDU has the highest capacity factor to December 31, 1993. In terms of lifetime performance for nuclear reactors over 500 MW worldwide, Canada's CANDU reactors comprised three of the ten best reactors, and New Brunswick Power's Point Lepreau was ranked second (Figure 7.4).

Surplus Capacity

Electric utilities are empowered with the difficult task of anticipating future electricity demand and ensuring that there are sufficient new generating facilities planned and built to supply the actual need.

During periods of fluctuating demand, such as we are experiencing now, this task provides a significant challenge. On occasion, when new generating facilities are completed and the expected demand does not materialize, the utility is faced with excess generating capacity. In the early-1970s, the construction of new generating stations was initiated mainly on the basis of expectations of continuing rapid growth in electricity demand. However, growth in demand slowed dramatically in the latter part of the decade and some of these newly constructed stations were temporarily surplus to domestic requirements.

In calculating surplus capacity, the generating capability, rather than generating capacity, is normally used. Generating capability measures the expected output of all the available generating facilities in a region at the time of firm peak load. This may differ significantly from the generating capacity measured by the nameplate rating of the equipment.

The variations between generating capability and generating capacity may be caused by a number of factors. These include: water levels in hydro reservoirs, the combined effects of derates and outages, weather effects, and fuel availability.

Reserve Margin

The reserve margin of an electrical system can be defined as the excess of generating capability for in-province use, over the in-province firm peak that occurred during the year, expressed as a percentage of in-province firm peak. Table 7.7 presents the reserve margins of the ten provinces and two territories in 1993. Utilities in the Yukon and Northwest territories have high reserve margins because of the logistics associated with serving remote communities. The extra generators allow the utilities to continue to provide service in the event of equipment failure. Where many communities can be connected together via an electric grid and facilities can be shared, the capacity reserve requirement can be reduced substantially.

Capacity Reserve Requirements

Normal practice in an electrical system is to reserve a certain amount of capacity (expressed as a percentage of firm peak load) to allow for scheduled maintenance, derates or failure of equipment and fluctuations in demand. This portion is usually called the capacity reserve requirement, and it varies from utility to utility, depending on the configuration and requirements of the particular system. Column 4 of Table 7.7 reports the capacity reserve

requirement in each province and territory for 1993.

Net Surplus Capacity

Net surplus capacity is defined as the reserve margin less the reserve capacity requirement. Table 7.7 indicates existing net surplus generating capacity by province and for Canada as a whole for 1993. With the exceptions of Prince Edward Island, Alberta, and British Columbia, all provinces and territories had net surplus capacity by the end of 1993. A weighted average for Canada was about eight per cent. Regions which have low generating capability rely on interconnections with neighbouring electrical systems to meet their peak requirements.

Hydroelectric Potential in Canada

There is still a large amount of undeveloped hydroelectric potential in Canada (Table 7.8). Although much of this is unlikely to be developed due to the remoteness of the sites, the physical difficulty of the terrain or environmental concerns, a significant amount could be developed over the next 25 years.

Tables and figures referred to in this chapter are on the following pages.

Tables & Figures

Table 7.1
Installed Generating Capacity by Fuel Type, 1960-1993

Fuel Type	Installed Generating Capacity						Average Annual Growth Rate	
	1960	1970	1980	1990	1992	1993	1960-1993	1992-1993
	(MW)						(per cent)	
Hydro	18 643	28 298	47 770	58 701	61 973	62 705	3.8	1.2
Thermal	4 392	14 287	28 363	31 174	32 720	33 401	6.5	2.1
Nuclear*	0	240	5 866	13 052	13 052	15 857	-	13.4
Tidal**	0	0	0	20	20	20	-	0.0
Total	**23 035**	**42 825**	**81 999**	**102 947**	**108 700**	**111 984**	**5.0**	**3.0**

* Commercial operation started in 1968.
** Commercial operation started in 1984.
Source: Electric Power Statistics, Volume II, Statistics Canada, catalogue 57-202

Table 7.2
Installed Generating Capacity by Fuel Type and Province, 1993

	Coal	Oil	Natural Gas	Nuclear	Hydro	Other	Total
	(MW)						
Nfld.	0	792	0	0	6650	5	7 447
P.E.I.	0	121	0	0	0	0	121
N.S.	1 383	539	0	0	390	18	2 330
N.B.	703	2 106	0	680	902	87	4 478
Que.	0	1 440	85	685	30 065	5	32 280
Ont.	10 628	2 554	909	14 492	7 209	159	35 951
Man.	369	16	4	0	4 498	23	4 910
Sask.	1 466	22	432	0	836	22	2 778
Alta.	5 581	18	1 807	0	823	152	8 381
B.C.	0	242	975	0	11 223	526	12 966
Yukon	0	57	0	0	77	0	134
N.W.T.	0	140	19	0	49	0	208
Canada	**20 130**	**8 052**	**4 231**	**15 857**	**62 722**	**992**	**111 984**

Source: Electric Power Statistics, Volume II, Statistics Canada, catalogue 57-204 and Natural Resources Canada

Table 7.3
Installed Generating Capacity by Province, 1960-1993

	Installed Generating Capacity						Average Annual Growth Rate	
	1960	1970	1980	1990	1992	1993	1960-1993	1992-1993
	(MW)							
Nfld.	314	1 248	7 195	7 462	7 447	7 447	10.4	0.0
P.E.I.	37	77	118	122	121	121	3.9	0.0
N.S.	507	931	2 029	2 156	2 330	2 330	4.9	0.0
N.B.	402	1 201	2 795	3 543	4 035	4 478	7.5	11.0
Quebec	8 920	14 047	20 531	28 873	31 362	32 280	4.0	2.9
Ontario	7 109	13 700	25 796	32 733	34 071	35 951	5.0	5.5
Manitoba	1 043	1 794	4 142	4 414	4 910	4 910	5.2	0.0
Sask.	761	1 533	2 340	2 846	2 778	2 778	4.5	0.0
Alberta	915	2 674	5 807	7 976	8 347	8 381	7.2	0.4
B.C.	2 963	5 473	10 525	12 497	12 966	12 966	4.8	0.0
Yukon	31	58	94	126	133	134	4.7	0.8
N.W.T.	33	89	180	199	200	208	5.9	4.0
Canada	**23 035**	**42 825**	**81 999***	**102 947**	**108 700**	**111 984**	**5.0**	**3.0**

* Includes confidential data, not available by province.

Source: Electric Power Statistics, Volume II, Statistics Canada, catalogue 57-202

Table 7.4
Canada's Largest Hydro Stations, 1993

Rank	Name	Province	Rated Capacity (MW)	Year of Initial Operation
1	Churchill Falls	Newfoundland	5 429	1971
2	La Grande 2	Quebec	5 328	1979
3	Gordon M. Shrum	B.C.	2 730	1968
4	La Grande 4	Quebec	2 651	1984
5	La Grande 3	Quebec	2 304	1982
6	Revelstoke	B.C.	1 843	1984
7	Mica	B.C.	1 736	1976
8	Beauharnois	Quebec	1 666	1932
9	Manic 5	Quebec	1 410	1970
10	Limestone	Manitoba	1 330	1990

Source: Electric Power Statistics,Volume III, Statistics Canada, catalogue 57-206, 1992

Table 7.5
Canada's Largest Conventional Thermal Stations, 1993

Rank	Name	Fuel Type	Province	Rated Capacity(MW)	Year of Initial Operation
1	Nanticoke	coal	Ontario	4 096	1973
2	Lakeview	coal	Ontario	2 400	1962
3	Lennox	oil	Ontario	2 200	1976
4	Sundance	coal	Alberta	2 200	1970
5	Lambton	coal	Ontario	2 040	1969
6	Richard L. Hearn	coal	Ontario	1 200	1951
7	Coleson Cove	oil	New Brunswick	1 050	1976
8	Burrard	natural gas	British Columbia	913	1961
9	Boundary Dam	coal	Saskatchewan	875	1959
10	Keephills	coal	Alberta	766	1983

Source: Electric Power Statistics, Volume III, Statistics Canada, catalogue 57-206, 1993

Table 7.6
Commercial Nuclear Power Plants in Canada, 1993

Rank	Plant Name	Province	Rated Net Capacity (MW)	Commissioning Date
1	Pickering A1	Ontario	515	1971
2	Pickering A2	Ontario	515	1971
3	Pickering A3	Ontario	515	1972
4	Pickering A4	Ontario	515	1973
5	Bruce A1	Ontario	769	1977
6	Bruce A2	Ontario	769	1977
7	Bruce A3	Ontario	769	1978
8	Bruce A4	Ontario	769	1979
9	Point Lepreau 1	New Brunswick	635	1983
10	Pickering B5	Ontario	516	1983
11	Gentilly 2	Quebec	638	1983
12	Pickering B6	Ontario	516	1984
13	Bruce B6	Ontario	837	1984
14	Pickering B7	Ontario	516	1985
15	Bruce B5	Ontario	860	1985
16	Pickering B8	Ontario	516	1986
17	Bruce B7	Ontario	860	1986
18	Bruce B8	Ontario	837	1987
19	Darlington 2	Ontario	881	1990
20	Darlington 1	Ontario	881	1992
21	Darlington 3	Ontario	881	1993
22	Darlington 4	Ontario	881	1993

Source: Electricity Branch, Natural Resources Canada

Table 7.7
Surplus Capacity in Canada, 1993

	Net Generating Capability for In-Province Use (1)	In-Province Firm Peak (2)	Reserve Margin (3)= ((1)-(2)) / (2)	Capacity Reserve Requirement (4)*	Net Surplus Capacity (5)=(3)-(4)
	(MW)			(per cent)	
Nfld.**	3 061	1 907	61	17	44
P.E.I.	157	143	10	15	-5
N.S.	2 320	1 902	21	20	1
N.B.	3 810	2 836	34	20	14
Quebec	36 453	30 932	18	10	8
Ontario	33 754	25 246	34	24	10
Manitoba	4 808	3 564	35	15	20
Sask.	3 087	2 482	24	15	9
Alberta	8 286	6 874	21	22	-1
B.C.	11 193	9 988	12	15	-3
Yukon	135	57	137	19	118
N.W.T.	186	89	109	30	79
Canada	**107 250**	**86 040**	**25**	**17**	**8**

*Expressed as a percentage of in-province firm peak.
**Includes Labrador.

Source: Electric Power Statistics, Volume I, Statistics Canada, catalogue 57-204

Table 7.8
Hydroelectric Capacity in Canada, 1993

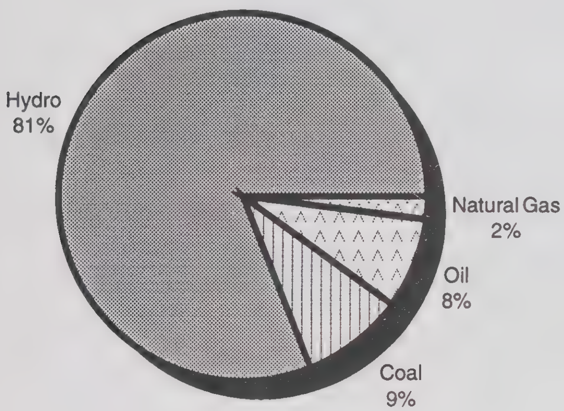
Province/Territory	In-Operation and Under Construction	Remaining Potential Gross*	Remaining Potential Identified**	Remaining Potential Planning***
	(MW)			
Newfoundland	6 656	5 201	4 623	2 555
Prince Edward Island	0	0	0	0
Nova Scotia	390	8 499	8 499	0
New Brunswick	903	940	600	440
Quebec	32 282	66 286	34 844	7 970
Ontario	7 217	12 385	12 385	4 008
Manitoba	4 498	8 360	5 260	5 260
Saskatchewan	836	2 189	935	870
Alberta	733	18 813	9 762	1 923
British Columbia	10 849	33 137	18 168	10 538
Yukon	77	18 583	13 701	350
Northwest Territories	53	9 229	9 201	2 473
Canada	**64 494**	**183 622**	**117 978**	**36 387**

* Gross Potential -- The total gross resource that could be developed if there were no technical, economic or environmental constraints (excludes sites already developed or under construction).
** Identified Potential -- Gross potential less sites that may not be developed for technical reasons.
*** Planning Potential -- Identified potential less sites that may not be developed for environmental or economic reasons. The planning potential thus comprises all those sites that are considered to be likely candidates for future development.

Source: Canadian electrical utilities and Natural Resources Canada

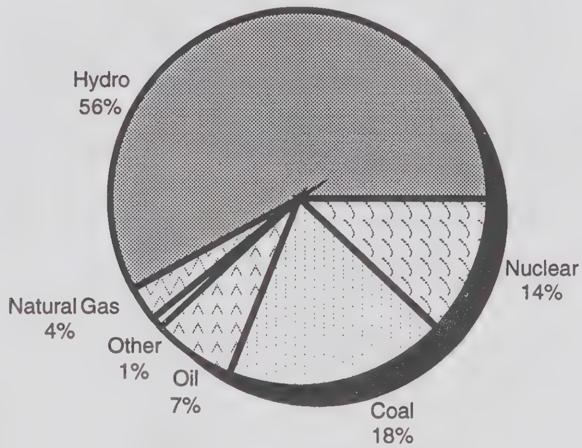
Figure 7.1 Installed Generating Capacity by Fuel Type

Total Capacity: 23 035 MW



1960

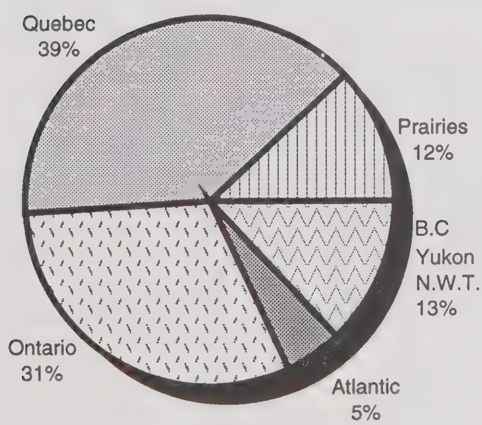
Total Capacity: 111 984 MW



1993

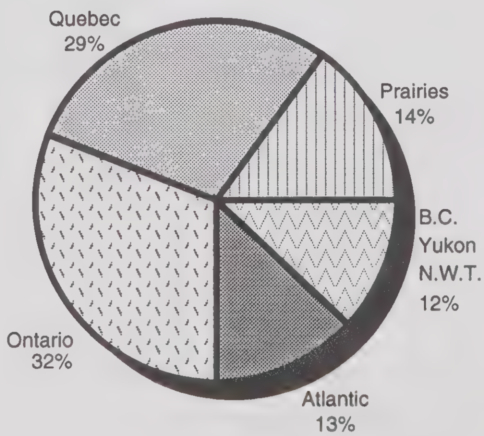
Figure 7.2 Installed Generating Capacity by Region

Total Capacity: 23 035 MW



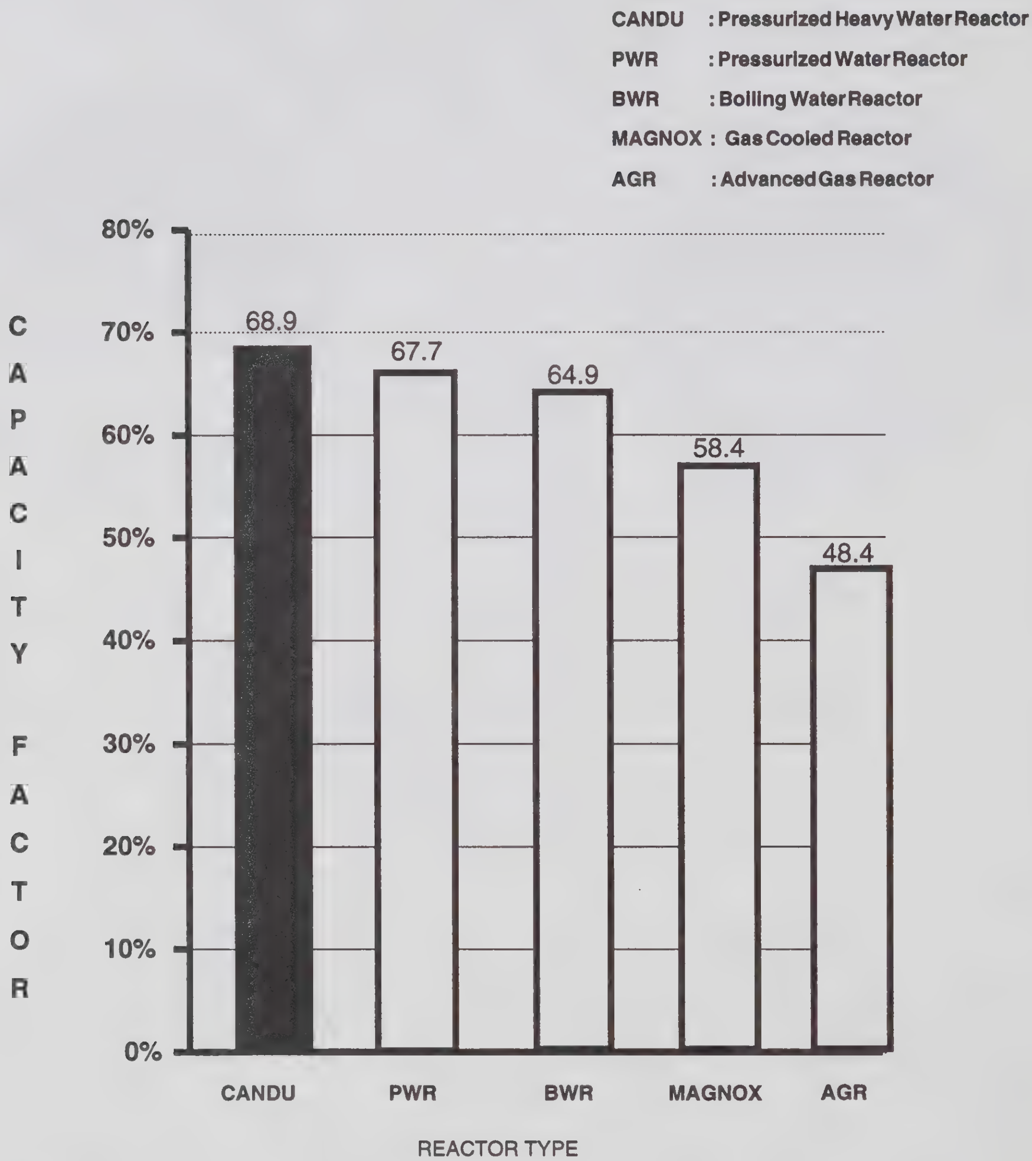
1960

Total Capacity: 111 984 MW



1993

Figure 7.3 Nuclear Reactor Performance Worldwide by Type*

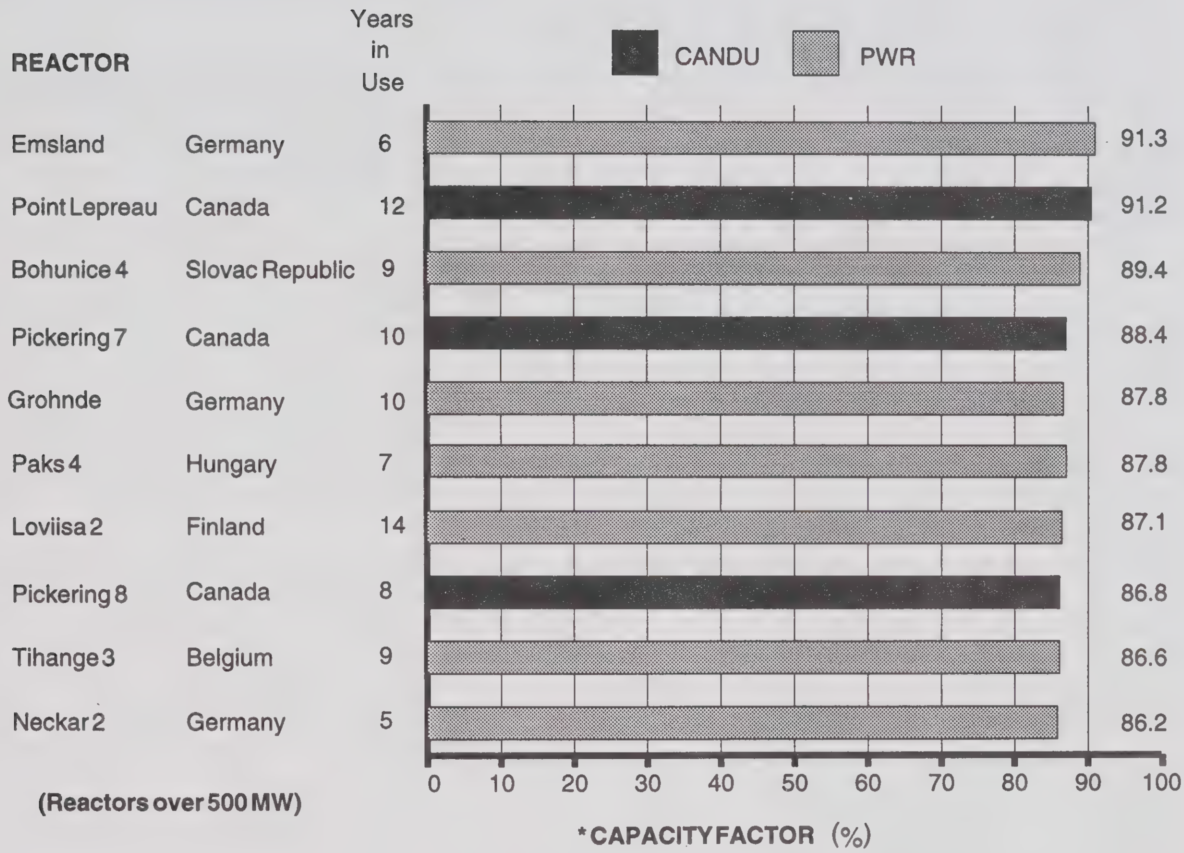


Reactors > 150 MW

* Lifetime to end of December 31, 1993

Source: World Nuclear Industry Handbook 1993 and Atomic Energy of Canada Ltd.

Figure 7.4 World Nuclear Reactor Performance to December 31, 1993



$$\text{*Capacity factor} = \frac{\text{actual electricity generation}}{\text{perfect electricity generation}}$$

Source: Nuclear Engineering International, April 1994

Chapter 8

Electricity Trade

International Trade

Electricity trade between Canada and the United States dates back to the beginning of the century. In 1901, the first electric power transmission line between the two countries was built at Niagara Falls which enabled abundant Canadian hydroelectric power to be marketed in the United States. This historical event set the stage for continued electricity exchanges between the two countries in a climate of international cooperation and coordination. During the early years, Canadian electricity exports to the U.S. were usually in the form of long-term firm power sales contracts because Canada needed the export contracts to finance construction of hydroelectric plants. Both Canadian and U.S. companies invested in generating capacity built in Canada for export.

Since 1921, electricity trade has been in Canada's favour in terms of quantity. Canada's net exports grew substantially from the early-1970's reaching a peak of 45 TWh in 1987, largely due to the high cost of thermal production in the United States.

Electricity trade between the United States and Canada is mainly attributed to the following:

- differences in the natural resources of the two countries have a significant impact on the level of trade. For instance, many Canadian provinces, such as Newfoundland, Quebec, Manitoba, and British Columbia have an abundance of hydroelectric resources that can be substituted for U.S. generation from fossil fuels;
- cost differences stimulate the selling of Canadian power to U.S. markets for profit;
- electric utilities benefit from the purchase of less costly Canadian supplies; and
- electrical energy supply systems in the U.S. and Canada have differences in seasonal peak demands, which makes surplus energy exchanges possible. While all electrical systems in Canada have their peak demand in winter, all electrical systems in the United States have their peak in summer.

Electricity trade between the United States and Canada provides a wide variety of benefits to consumers and electric utilities in both countries. These benefits include:

- *rate reduction:* electric utilities normally use export revenues to reduce their revenue requirements, which, in turn, reduces rate increases;
- *surplus energy sales:* the existence of secondary markets, including storage, to utilize energy from renewable resources that would otherwise be wasted;
- *economy interchange:* the interchange of electricity between two utilities which results in a reduction of production costs;
- *diversity exchange:* non-coincident peak loads which allow utilities to share generation and realize economic benefits;
- *reserve sharing:* agreements for mutual generation support so that new power plant requirements are decreased; and
- *coordination of planning and operation:* cooperation between utilities, mainly in generation facility planning, operation, and maintenance, to reduce investment requirements and distribute maintenance outages so that system operations are optimized.

In 1993, electricity exports to the United States increased 17 per cent over 1992, reaching about

29 364 GWh, while imports rose 46 per cent to 2 690 GWh. Exports accounted for 5.8 per cent of Canada's total electricity generation in 1993, up from 5.2 per cent in 1992. Export revenue also increased significantly, by 27 per cent, from $708 million in 1992 to $858 million in 1993, while import costs remained at approximately $85 million.

Export increases in 1993 occurred mainly in Ontario, Quebec, and Manitoba due to improved water flows in these provinces. An increase in demand for electricity in New York and New England also contributed to the increase in exports.

Water flow in British Columbia was poor in 1993, leading to a 54 per cent decline in export sales from the province.

Firm exports were the main type of electricity exports to the United States, accounting for 51 per cent of the total in 1993. Firm exports accounted for a much greater share of the total export revenue; 60 per cent compared with 40 per cent for interruptible exports.

Average firm and interruptible export revenues rose in 1993 following a decline in 1992. Average firm revenues rose 5 per cent to 34.3 mills per kWh, while average interruptible export revenue rose 8 per cent to 23.9 mills per kWh. The increase in firm revenues was due largely to Manitoba Hydro's new firm sales to Minnesota.

Hydro generated electricity continued to be the main source of Canada's electricity exports, accounting for 79 per cent in 1993 compared to 76 per cent in 1992. Coal-fired exports rose from 9 per cent to 13 per cent, while the share of oil-fired exports declined slightly to 1 per cent. Nuclear power remained at 5 per cent in 1993. Exports from natural gas accounted for only 2 per cent of total exports compared to to 8 per cent in 1992.

U.S. imports of Canadian electricity, as a percentage of total electrical energy demand in the United States, increased slightly from 0.7 per cent in 1991 to 0.9 per cent in 1992. However, U.S. dependence on Canadian exports was higher in certain regions. Exports to New England accounted for 8 per cent of the region's total electricity consumption in 1992. The corresponding ratio was 4 per cent for the Midwest and 2 per cent each for New York, the Pacific Northwest, California, and the Southern Nevada region.

Electricity Trade and the Economy

The export of electricity is an important aspect of Canada's foreign trade. While total electricity export revenue accounted for only 0.5 per cent of total merchandise exports and 4.3 per cent of total energy exports in 1993, net electricity export revenue accounted for 4.4 per cent of Canada's balance of trade and 5.9 per cent of Canada's total energy trade balance in 1993. Canadian energy trade by fuel type during the period 1975-93 is reported in Table 8.11.

Interprovincial Trade

In Canada, provincial electric utilities trade electricity across provincial borders for the same reasons that trade occurs between Canada and the United States: to reduce costs, maximize profits, and mitigate emergencies. Electric utilities import electricity when imports are less expensive than their own production. Similarly, electric utilities export power when they can both meet domestic demand and maximize profits by marketing additional power to outside buyers.

Although Canadian interprovincial electricity trade has consistently been greater than that between Canada and the United States since 1975, it is mainly dominated by the Churchill Falls power contract signed between

Newfoundland and Quebec. The Churchill Falls hydro project was built by Hydro-Québec, however, Hydro-Québec only has a minority interest in the power plant. The Churchill Falls (Labrador) Corporation Limited operates the power plant, which began producing electricity in 1972. Under the power contract, about 90 per cent of the Churchill Falls production is sold to Quebec. During the past 10 years, electrical energy sold to Quebec from Churchill Falls accounted for about 66 per cent of Canada's total interprovincial electricity trade.

Interprovincial electricity transfers during the period 1984-93 are summarized in Table 8.13. More information on exports and imports by province is provided in Figure 8.1 and Table A5 in Appendix A.

Tables and figures referred to in this chapter are on the following pages.

Tables & Figures

Table 8.1
Canada-U.S. Electricity Trade, 1960-1993

	Exports* (GWh) (1)	Exports as a Percentage of Total Generation (2)	Export Revenues ($million) (3)	Imports* (GWh) (4)	Imports as a Percentage of Total Disposal** (5)	Import Cost ($million) (6)	Net Exports (GWh) (7)=(1)-(4)	Net Exports $Million (8)=(3)-(6)
1960	5 496	4.8	14	357	0.3	1	5 139	13
1965	3 684	2.6	8	3 575	2.5	3	109	5
1970	5 631	2.8	32	3 245	1.6	9	2 386	23
1975	11 409	4.2	104	3 972	1.5	3	7 819	102
1980	28 224	7.7	773	168	0.1	3	28 056	791
1985	41 441	9.3	1 425	231	0.1	9	41 210	1 416
1987	45 359	9.4	1 211	536	0.1	12	44 823	1 199
1988	29 729	6.1	880	2 853	0.6	63	26 879	817
1989	18 462	3.8	661	8 747	1.9	292	9 715	369
1990	16 494	3.5	547	15 543	3.5	556	951	(9)
1991	19 828	4.1	558	1 905	0.4	71	17 923	487
1992	26 224	5.2	708	1 836	0.4	84	24 388	625
1993	29 364	5.8	858	2 692	0.6	85	26 672	773

* Exports and imports prior to 1977 include service exchanges.
** Total disposal refers to total electricity available for domestic consumption.
Source: Electric Power Statistics, Volume II, Catalogue 57-202, Statistics Canada and Natural Resources Canada

Table 8.2
Provincial Shares of Canadian Electricity Exports, 1960-1993*

Year	New Brunswick	Quebec	Ontario	Manitoba	Sask.	British Columbia	Canada
1960	3.0	10.4	86.6	0.0	0.0	0.0	100.0
1965	6.4	1.3	84.0	0.0	0.0	8.3	100.0
1970	13.4	0.9	63.9	5.2	0.0	16.6	100.0
1975	14.2	8.0	42.5	10.3	0.0	25.0	100.0
1980	13.8	28.7	40.5	11.8	0.0	5.2	100.0
1985	14.8	23.1	22.5	13.6	0.3	25.7	100.0
1989	24.1	30.9	14.7	6.6	0.1	23.6	100.0
1990	25.4	30.9	4.5	11.7	0.3	27.2	100.0
1991	15.6	29.2	11.7	16.7	0.3	26.6	100.0
1992	6.6	33.7	7.8	23.1	0.3	28.5	100.0
1993	6.1	39.9	16.9	26.7	0.6	9.9	100.0

* Excludes non-cash exchanges
Source: National Energy Board

Table 8.3
Firm and Interruptible Exports by Province, 1993*

	Firm	Interruptible	Firm	Interruptible
	(GWh)		(per cent)	
New Brunswick	1 257	521	71	29
Quebec	8 092	3 615	69	31
Ontario	245	4 718	5	95
Manitoba	3 466	4 358	44	56
Saskatchewan	0	184	0	100
British Columbia	1 889	1 018	65	35
Canada	**14 950**	**14 414**	**51**	**49**

* Exchanges are excluded

Source: National Energy Board

Table 8.4
Electricity Exports to the United States by Type, 1960-1993

	Quantity (GWh)		Revenue ($1000)		Quantity Share (%)		Revenue Share (%)	
	Firm*	Interruptible**	Firm	Interruptible	Firm	Interruptible	Firm	Interruptible
1960	1 040	4 456	4 328	10 023	19	81	30	70
1965	635	3 049	4 261	3 322	17	83	56	44
1970	984	4 648	6 828	25 309	18	82	21	79
1975	2 375	9 034	20 382	84 488	21	79	19	81
1980	7 232	20 992	156 731	636 760	26	74	20	80
1985	12 305	29 136	547 109	877 657	30	70	38	62
1990	8 701	7 794	346 513	200 147	53	47	63	37
1991	8 789	11 039	310 049	247 484	44	56	56	44
1992	12 168	14 056	397 184	311 070	46	54	56	44
1993	14 950	14 414	513 579	344 637	51	49	60	40

* Electrical energy intended to be available at all times during the period of the agreement for its sale.

** Energy made available under an agreement that permits curtailment or interruption of delivery at the option of the supplier.

Source : National Energy Board

Table 8.5
Average Export Revenues, 1960-1993

Year	Firm	Interruptible	Total
		(mills/kWh)	
1960	4.2	2.3	2.6
1965	6.7	1.1	2.1
1970	6.9	5.5	5.7
1975	8.6	9.4	9.2
1980	21.7	30.3	28.1
1985	44.5	30.1	34.4
1990	39.8	25.7	33.1
1991	35.3	22.4	28.1
1992	32.6	22.1	27.0
1993	34.3	23.9	29.2

Source: Calculated from Table 8.4

Table 8.6
Electricity Exports and Revenues by Province, 1992-1993*

	Quantity (GWh)			Revenue (million $)			Average Revenue (mills/kWh)		
	1992	1993	% Change	1992	1993	% Change	1992	1993	% Change
N.B.	1 730	1 778	3	88.45	80.55	-9	51.1	45.2	-12
Que.	8 827	11 707	25	269.22	365.10	36	30.5	28.3	-7
Ont.	2 056	4 964	59	59.23	131.62	172	28.8	26.5	-8
Man.	6 058	7 824	23	95.70	204.96	113	15.8	26.1	65
Sask.	79	184	57	1.70	3.45	103	21.4	18.8	-12
B.C.	7 474	2 907	-119	193.96	114.11	-45	26.0	36.6	41
Canada	**26 224**	**29 364**	**14**	**708.25**	**858.22**	**21.2**	**27.0**	**29.2**	**8**

* Excludes non-cash exchanges.
Source: National Energy Board

Table 8.7
Average Export Revenues by Province, 1992 vs 1993

	Firm		Interruptible	
	1992	1993	1992	1993
	(mills/kWh)			
New Brunswick	58.3	50.8	32.5	31.8
Quebec	30.5	29.7	30.5	25.2
Ontario	39.7	25.9	27.2	26.5
Manitoba	25.1	39.1	13.7	15.7
Saskatchewan	-	-	21.4	18.8
British Columbia	28.5	35.3	24.7	39.0
Canada	**32.6**	**34.3**	**22.1**	**23.9**

Source: "Canada-U.S. Electricity Trade Report", Natural Resources Canada

Table 8.8
Generation Sources of Canadian Electricity Exports, 1975-1993

	Hydro	Imported Coal	Imported Oil	Domestic Coal/Oil	Nuclear	Natural Gas	Total
				(GWh)			
1975	5 724	4 838	494	353	0	-	11 409
1976	6 973	4 323	1 206	302	0	-	12 804
1977	7 926	8 514	2 961	555	0	-	19 957
1978	7 290	10 476	2 260	411	0	-	20 437
1979	15 213	11 587	3 354	128	177	-	30 458
1980	14 135	10 599	2 867	593	30	-	28 224
1981	21 182	10 901	1 940	665	42	-	34 730
1982	20 114	10 315	1 959	502	96	-	32 986
1983	21 978	11 704	1 201	519	1 856	-	37 258
1984	22 807	10 582	1 552	711	1 911	-	37 563
1985	28 836	8 245	1 157	956	2 247	-	41 441
1986	25 727	5 389	846	825	2 484	-	35 271
1987	34 065	7 575	1 270	408	2 041	-	45 359
1988	19 621	4 531	1 393	2 033	2 151	-	29 729
1989	9 054	1 452	1 089	2 214	2 032	2 621	18 462
1990	11 299	266	885	1 244	2 054	796	16 494
1991	14 415	1 546	610	697	2 172	388	19 828
1992	20 121	1 339	416	1 083	1 200	2 065	26 224
1993	22 978	2 934	263	1 088	1 501	601	29 364

Source: Compiled from National Energy Board Statistics

Table 8.9
Energy Sources of Electricity Exports, 1993

	Natural Gas	Oil	Coal	Nuclear	Hydro	Other*	Total	Energy Exported
				(per cent)				(GWh)
New Brunswick	-	20	0	59	10	11	100	1 778
Quebec	-	-	-	-	100	-	100	11 707
Ontario	-	0	62	15	21	1	100	4 964
Manitoba	-	-	-	-	100	-	100	7 824
Saskatchewan	-	-	100	-	-	-	100	184
British Columbia	21	-	30	-	43	6	100	2 907
Canada	**2**	**1**	**14**	**5**	**77**	**2**	**100**	**29 364**

* Refers to U.S. electricity imports that are subsequently exported.
Source: Natural Resources Canada

Table 8.10
Exporting Provinces and Importing Markets, 1993*

Exporting Province	Importing Market	Quantity (MWh)	Value ($)
New Brunswick	Maine	983 270	40 049 614
	Massachusetts	763 896	38 002 319
Quebec	Maine	1 128	89 546
	Vermont	1 910 208	94 269 116
	New England (NEPOOL)**	6 454 550	141 823 388
	New York	3 584 633	101 597 035
Ontario	Vermont	113 651	7 587 539
	New York	1 884 767	53 694 262
	Michigan	2 419 866	63 896 263
	Minnesota	2 835	71 226
Manitoba	Minnesota	5 308 691	164 439 703
	North Dakota	705 078	12 137 080
Saskatchewan	North Dakota	229 450	3 452 732
British Columbia	Washingon	1 786 524	63 996 765
	Oregon	1 081 483	40 756 614
	Montana	3 040	120 130
	California	19 239	761 284
	Nevada	1 049	34 813
	Alaska	410	27 142
Canada	**United States**	**27 506 762**	**826 806 571**

* Excludes non-cash exchanges.
** The New England Power Pool (NEPOOL) coordinates electrical service to member utilities in New Hampshire, Maine, Vermont, Massachusetts, Conneticut, and Rhode Island.
Source: National Energy Board

Table 8.11
Canadian Energy Trade, 1975-1993

	Oil	Natural Gas	Coal	Electricity	Uranium	Total Energy
			($ million)			
1975						
Exports	3 684	1 092	483	104	133	5 496
Imports	3 508	8	643	13	12	4 184
Balance	**176**	**1 084**	**-160**	**91**	**121**	**1 312**
1980						
Exports	5 352	3 984	824	773	870	11 803
Imports	7 545	0	882	3	17	8 447
Balance	**-2 193**	**3 984**	**-58**	**770**	**853**	**3 356**
1985						
Exports	9 379	4 011	2 041	1 425	825	17 681
Imports	5 315	0	1 077	8	28	6 428
Balance	**4 064**	**4 011**	**964**	**1 417**	**797**	**11 253**
1990						
Exports	9 298	3 280	2 276	539	315	15 708
Imports	7 384	0	684	568	105	8 741
Balance	**1 914**	**3 280**	**1 592**	**-29**	**210**	**6 967**
1991						
Exports	9 607	3 512	2 206	558	290	16 169
Imports	6 104	33	523	71	62	6 793
Balance	**3 503**	**3 479**	**1 683**	**487**	**228**	**9 376**
1992						
Exports	9 801	4 608	1 884	708	497	17 498
Imports	5 887	50	647	84	114	6 775
Balance	**3 914**	**4 558**	**1 237**	**624**	**383**	**10 723**
1993						
Exports	10 936	5 778	2 070	858	499	20 140
Imports	6 399	47	484	85	127	7 142
Balance	**4 537**	**5 731**	**1 586**	**773**	**372**	**12 998**

Source: Statistics Canada, Exports by Commodities (65-004) and Imports by Commodities (65-007)

Table 8.12
Annual Canadian Interprovincial Electricity Trade, 1960-1993

Year	Total Canadian Generation (GWh)	Delivered to other Provinces (GWh) With Churchill Falls*	Delivered to other Provinces (GWh) Without Churchill Falls	Percentage of Interprovincial Transfers to Total Generation With Churchill Falls	Percentage of Interprovincial Transfers to Total Generation Without Churchill Falls
1960	114 378	7 108	7 108	6.2	6.2
1965	144 274	6 230	6 230	4.3	4.3
1970	204 723	8 137	8 137	4.0	4.0
1975	273 392	49 198	19 684	18.0	7.2
1980	367 306	52 709	14 965	14.4	4.1
1985	446 413	51 663	19 917	11.6	4.5
1989	482 158	36 176	11 809	7.5	2.4
1990	465 967	37 499	11 335	8.0	2.4
1991	489 227	38 530	12 164	7.9	2.5
1992	501 523	41 586	15 601	8.3	3.1
1993	511088	40 007	9 758	7.8	1.9

* The Churchill Falls project was completed in 1974 (the initial operation started in 1971). Over 90% of the energy it produces flows into Quebec under a contract that terminates in the year 2041.

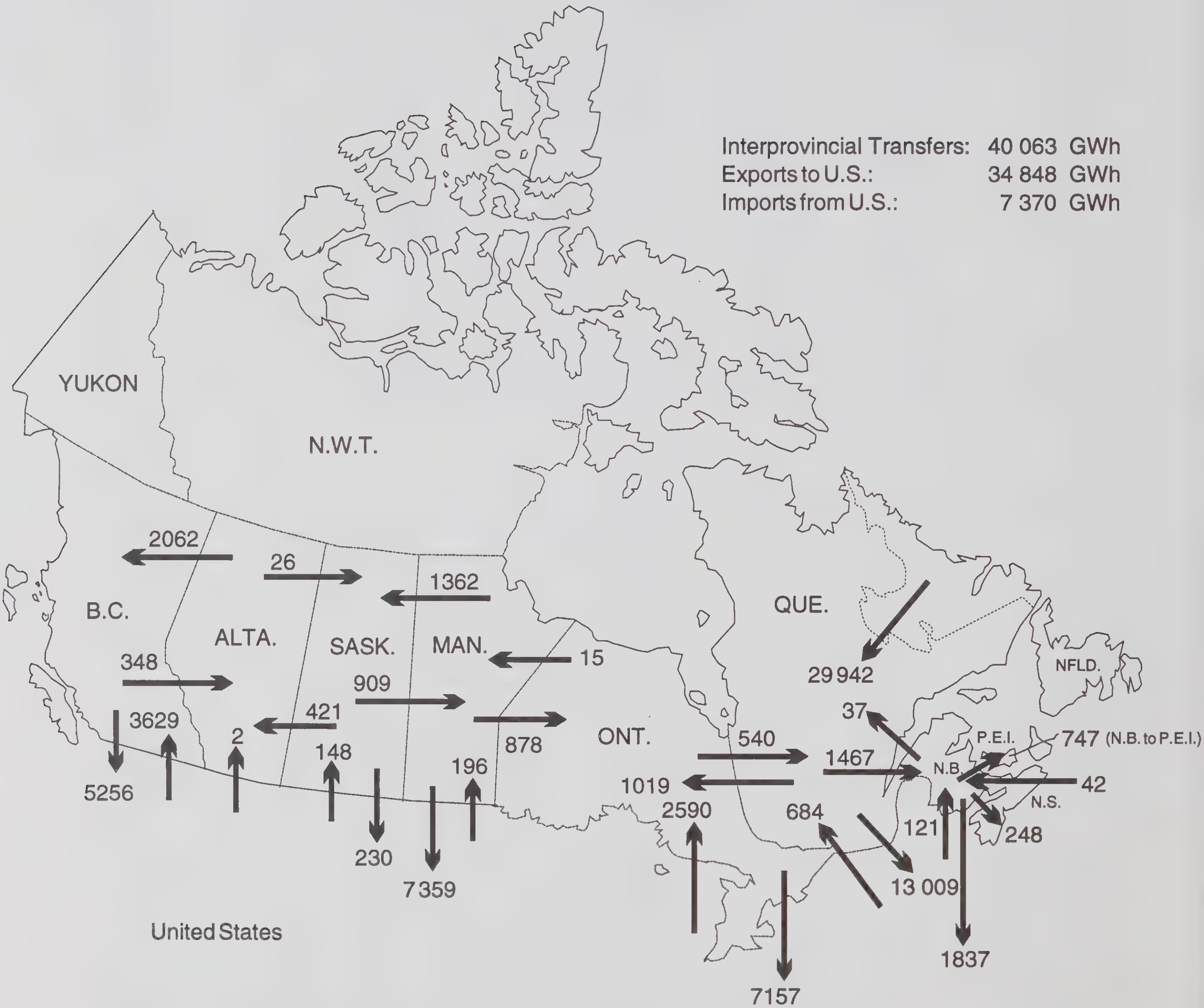
Source: Natural Resources Canada

Table 8.13
Interprovincial Electricity Trade by Destination, 1984-1993

	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
					(GWh)					
Nfld. to Que.	36 012	31 836	30 695	30 393	30 727	24 367	26 164	26 366	25 985	29 942
N.S to N.B.	271	190	71	82	166	341	116	50	67	42
N.B. to N.S.	303	360	620	659	186	441	365	444	253	248
N. B. to P.E.I.	550	585	610	483	486	622	672	690	738	747
N.B. to Que.	0	2	0	20	309	951	1 116	1 408	3 354	37
Que. to N. B.	4 342	5 951	7 204	6 840	2 690	1 966	2 659	3 383	3 858	1 467
Que. to Ont.	7 364	8 685	7 292	5 942	2 289	1 032	690	729	651	1 019
Ont. to Que.	68	106	17	15	43	80	134	109	187	540
Ont. to Man.	2	0	5	3	22	11	6	0	14	15
Man. to Ont.	940	959	735	1 050	538	1 303	1 636	1 482	1 552	878
Man. to Sask.	1 593	1 530	1 211	1 262	1 370	1 171	1 058	1 152	1 561	1 362
Sask. to Man.	1 299	1 240	1 076	1 220	1 109	1 115	1 047	975	951	909
Sask. to Alta.	3	0	0	0	0	15	39	23	132	421
Alta. to Sask.	0	0	0	0	0	42	94	116	23	26
Alta. to B.C.	259	182	617	710	1 218	2477	1 242	948	1 993	2 062
B.C. to Alta.	296	37	553	521	364	242	461	655	267	348
Total	**54 302**	**51 663**	**50 706**	**49201**	**41 517**	**36 176**	**37 499**	**38 530**	**41 586**	**40 063**

Source: National Energy Board

Figure 8.1 Electricity Trade, 1993 (GWh)*



*Includes non-cash exchanges

Transmission

Transmission Circuit Length

The electric power system in Canada consists of three interrelated functions: the generating system which produces the power; the transmission network which conducts the flow of power from the point of generation to the point of distribution; and the distribution system which delivers the power to consumers. In most provinces, all three of these interrelated functions are provided by one or a few major electric utilities.

The electrical transmission network in Canada has evolved from a simple system designed to serve customers at the local level into a highly complex interconnected system. In the early years of the 20th century, relatively small generating plants were situated close to the loads which they served, with power transmitted at low voltages under 60-kV.

Fast growth in electricity demand throughout the early 20th century brought forth successively larger power plants that were constructed farther away from load centres and nearer to abundant water resources. Transmission systems were used to distribute power to the geographically dispersed load areas. The integrated electric power system, coupled with the growth in interconnection of previously isolated power networks, led to the development of a new generation of higher voltage transmission in the range of 100 to 230-kV.

After World War II, in response to rapid electrification and installation of larger hydro and thermal generating stations, much higher voltages of transmission lines, such as 345-kV, 500-kV, 735-kV, and ±450(DC) were introduced into commercial operation.

Total circuit length of electrical transmission in Canada for lines rated at 50-kV and above, increased by only 724 km in 1993, much less than the 1088 km in 1992. The total length of Canadian bulk transmission is now 155 328 km, with the largest share (32 per cent) being in the 100-kV to 149-kV range. Another 25 per cent is in the 200-kV to 299-kV range, while 21 per cent is between 50-kV and 99-kV (Table 9.1).

Newfoundland and Quebec are the only two provinces with transmission lines over 600-kV. Newfoundland has three 735-kV lines wheeling power from its Churchill Falls hydro station in Labrador to Quebec City and Montreal, and Quebec has five 735-kV lines and one ±450-kV high-voltage direct current (HVDC) line delivering power from three hydro stations in the James Bay region to Montreal and the United States. Quebec also has a 765-kV line used mainly for export purposes, which delivers power from Chateauguay to the State of New York.

In 1993, transmission line additions within the provinces were found mainly in Newfoundland, Nova Scotia, Quebec, Ontario, Manitoba and New Brunswick. Newfoundland Light and Power completed its 66-kV line from Oxen Pond to Stamps Lane by adding 256 km to its system in 1993. Nova Scotia Power increased its system by 212 km with the addition of one 345-kV line from Hopewell to Woodbine, which is connected with the Point Aconi coal-fired station. Hydro-Québec increased its 315-kV line by 167 km, linking Brisay to La Forge 2, La Forge 2 to Nikamo, and Nikamo to La Forge 1. Ontario Hydro increased its 500-kV line by 46 km from Clairville to Cherrywood. Ontario Hydro also extended its 230-kV line by 8 km from Cherrywood to Markham. Manitoba Hydro completed its 230-kV line from Dorsey to LaVerendry in 1993 and added 27 km to its system. As well, New Brunswick Power extended its 345-kV line by adding 8 km to the newly completed Belledune plant.

Presently, there are only 7 in-province transmission lines under construction ranging

from 230-kV to 735-kV, with a total circuit length of about 1597 km. Hydro-Québec is building a 735-kV line linking Chissibi to Jacques Cartier, with a total circuit length of 965 km. Hydro-Québec is also building one 315-kV line in the James Bay area, linking LG-2A to Radisson, and a 69-kV line from Lac Robertson to La Tabatière.

Ontario Hydro is in the process of adding two more 500-kV lines. One will connect the Lennox oil-fired station (near Kingston) with Bowmanville and the other will link Nanticoke and Middleport.

In British Columbia, another 500-kV line presently under construction will connect Williston with Kelly Lake. The total circuit length for this line will be 330 km.

Interprovincial Transmission

To facilitate energy exchanges and enhance the reliability of electrical systems operation, there are now 36 major provincial interconnections, with a total transfer capability of about 10 145 MW (Table 9.2). No provincial interconnection was added in 1993.

Due to slow economic growth, no provincial interconnections are planned for the time being.

International Transmission

Interconnections play a major role in modern power systems. Most Canadian utilities have both east-west and north-south lines that allow exchanges of power and energy. No international interconnection was completed in 1993.

There are now over 100 international transmission lines in place to provide for Canada's international electricity trade. Although most of these lines are quite small, there are 37 bulk power interties rated at 69-kV or higher, with a total power transfer capability of 18 900 MW (Table 9.3).

B.C. Hydro is in the process of planning two 230-kV and one 500-kV international transmission lines. The new lines will increase B.C. Hydro's total firm power transfer capability by about 1700 MW. The lines are expected to be in service by 1999 and 2003, respectively. New Brunswick Power is also planning to build a 345-kV line from Lepreau to Orrington of Maine. The transfer capability is estimated at 600 MW and is expected to be in service by 1998 (Table 9.4).

Long-Distance Transmission

Canada is a world leader in long-distance electric power transmission, in both extra-high-voltage (EHV) alternating current and HVDC. A major influence on the development of Canada's expertise in these areas has been the country's abundant water power resources. Early in the century, pioneering efforts in high-voltage transmission resulted in the initial development of hydroelectric power at Niagara Falls to supply the growing needs of communities in southern Ontario. In Quebec, the first 50-kV transmission lines were constructed to bring power from Shawinigan to Montreal.

After the harnessing of major hydroelectric sites close to load centres, it became necessary to develop remote hydroelectric sources in several provinces and to integrate these sources into the power system over long-distance EHV and HVDC transmission lines. In 1965, Hydro-Québec installed the world's first 735-kV class transmission system. This system now extends over 1100 km from the Churchill Falls development in Labrador to Montreal. A comparable system of about the same distance extends from the James Bay development to Quebec's load centres.

In Manitoba, pioneering work was done under federal financial assistance to develop the ±450-kV HVDC system which now brings hydroelectric power from the Nelson River generating stations to customers in southern Manitoba. Recently, Hydro-Québec built a ±450-kV HVDC line delivering power from La Grande 2 station at Radisson to the United States. Ontario and British Columbia also have extensive EHV systems in the 500-kV class (Figure 9.1).

Such advances in Canadian transmission techniques have provided not only for long-distance bulk transmission, but also for extensive interconnections between neighbouring provinces and between Canada and the United States (Figure 9.2).

Reliability of Electric Service

Reliability of electric service has always been of prime importance to the electrical system. The reliability of supply is reflected in terms of frequency and duration of interruptions (outages) to the customer. The reliability of an electricity supply system, particularly the transmission and distribution segments of the system, is determined by a variety of factors, such as scheduled interruptions, loss of supply, tree contact, lightning, defective equipment, adverse weather, adverse environment, human elements, and other interference. Canada with its vast territory, long and severe winters, and its large hydro-electric plants which are often located far from population centres, is likely to be at a disadvantage compared to countries with smaller geographic areas and greater population density.

In Canada, the most commonly used indices to measure the reliability of electric service are the *System Average Interruption Frequency Index (SAIFI)*, the *System Average Interruption Duration Index (SAIDI)*, and the *Average Interruption Time Per Customer Per Year.*

SAIFI is the average number of interruptions experienced per customer per time unit. It is calculated by dividing the number of customer interruptions observed in a year by the number of customers affected.

SAIDI is the average interruption duration for customers served during a year. It is calculated by dividing the sum of all customer sustained interruption durations during the year by the number of customers served during the year.

The *Average Interruption Time Per Customer Per Year* is the product of SAIFI and SAIDI.

Figure 9.3 provides a comparison of the frequency of supply interruptions per customer per year for 14 major Canadian electricity suppliers in 1993. There is considerable variation in performance across Canada, for example, the Yukon Electrical Company shows an interruption frequency eight times higher than the Edmonton Power figure, and although Ontario Hydro serves electricity in a vast territory under severe weather, its reliability is one of the best in Canada. Hydro-Québec, B.C. Hydro, and Manitoba Hydro are predominately hydroelectric systems, however, the interruption frequency of Hydro-Québec's system is 3.6 times higher than that of B.C. Hydro and about three times higher than the Manitoba Hydro figure.

The average frequency of interruptions for Canada as a whole was 2.65 interruptions per customer per year in 1993, compared with 3.10 for 1992. In 1991, a total average for Japan and Australia was 0.35 and 2.6 interruptions per customer per year.

The duration of interruptions is reflected, in part, by how quickly the various electric authorities correct faults in the system. As was pointed out earlier, many factors will determine the duration of interruptions. Some of these factors such as the severity of storms, fires, and floods will be out of the electricity suppliers' control. As a

result, considerable variation in the duration of interruption may be expected from year to year.

Figure 9.4 presents the duration of interruptions for 14 major Canadian electric utilities. As in the case of interruption frequency, the duration of interruptions in Canadian electrical systems varies considerably, ranging from 27 minutes for Edmonton Power to more than five hours for Newfoundland Light and Power and four hours for Alberta Power. It is interesting to note that both Edmonton Power and Alberta Power serve the same province of Alberta. Edmonton Power's much shorter interruption duration is partially due to the fact that it is a municipal utility serving electricity in a much smaller area with a greater population density than that of Alberta Power.

Of the 14 utilities, Ontario Hydro rates second in having the shortest interruption duration with only 32 minutes. Although Hydro-Québec has a much higher frequency of outages when compared to other Canadian electrical systems, the short duration of its outages in 1993 reflects a quick response time to faults in the system.

As indicated in Figure 9.4, the average customer outage duration in Canada was 110 minutes in 1993, up from 74 minutes in 1992. There are no corresponding figures for other countries in the same year. However, compared with other countries' 1991 figures, performance for Canada is less satisfactory. According to the Australian Bureau of Industry Economics, the average customer duration per interruption was 124 minutes for Australia, 94 minutes for Japan, and 66 minutes for U.S. public utilities.

The product of average interruption frequency and average interruption duration provides an estimate of average interruption time per customer per year. The comparisons summarized in Figure 9.5 indicate that there are significant differences in system performance by province. For instance, the average interruption time per customer per year for Edmonton Power was only 17 minutes, compared with 1483 minutes for Newfoundland Light and Power.

On average the Canadian systems were relatively higher in interruption frequency and faster in dealing with faults in transmission and distribution. Therefore the average interruption time per customer per year was quite comparable with other countries, about 222 minutes, as reported in Figure 9.5. According to the same Australian source for the 1991 data, the average interruption time per customer per year was 33 minutes for Japan, 208 minutes for rural U.S, and 324 minutes for Australia.

Tables and figures referred to in this chapter are on the following pages.

Tables & Figures

Table 9.1
Transmission Circuit Length in Canada, 1993

	50-99 kV	100-149 kV	150-199 kV	200-299 kV	300-399 kV	400-599 kV	600 kV and up	Total
				(km)				
Nfld.	2 612	1 985	-	2 005	-	-	612	7 214
P.E.I.	390	193	-	-	-	-	-	583
N.S.	2 027	1 703	-	1 236	674	-	-	5 640
N.B.	2 716	2 048	-	629	1 189	-	-	6 582
Quebec	4 150	7 762	2 266	3 810	7 305	1 555	9 955	36 803
Ontario	247	12 318	-	13 971	6	3 037	-	29 615
Manitoba	6 756	4 266	-	4 503	-	2 042	-	17 567
Sask.	4 849	4 534	-	3 250	-	-	-	12 633
Alberta	3 481	9 216	-	5 926	-	215	-	18 838
B.C.	4 996	4 702	316	3 430	403	5 344	-	19 191
Yukon	65	497	-	-	-	-	-	562
N.W.T.	100	-	-	-	-	-	-	100
Canada	**32 389**	**49 224**	**2 582**	**38 760**	**9 577**	**12 229**	**10 567**	**155 328**
	(21%)	(32%)	(2%)	(25%)	(6%)	(8%)	(6%)	(100%)

Source: Statistics Canada Publication 57-202 and Natural Resources Canada

Table 9.2
Provincial Interconnections at Year-End, 1993

Connection	Voltage	Design Capability*
	(kV)	(MW)
British Columbia - Alberta	1 x 500	800
	1 x 138	110
Alberta - Saskatchewan	1 x 230	150
Saskatchewan - Manitoba	3 x 230	400
	2 x 110	100
Manitoba - Ontario	2 x 230	260
	1 x 115	
Ontario - Quebec	4 x 230	1 300
	7 x 120	
Quebec - Newfoundland	3 x 735	5 225
Quebec - New Brunswick	2 x ±80(DC)	700
	2 x 345	
	2 x 230	300
New Brunswick - Nova Scotia	2 x 138	600
	1 x 345	
New Brunswick - P.E.I.	2 x 138	200

* Actual transfer capabiity in practice will be different from design capability.
Source: Natural Resources Canada

Table 9.3
Major Interconnections Between Canada and the United States, 1993*

Province	State	Voltage (kV)	Design Capability*** (MW)
New Brunswick	Maine	1 x 345	600
		1 x 138	60
		5 x 69	155
Quebec	New York	1 x 765	2 300
	New York	2 x 120	300
	Vermont	3 x 120	375
	New Hampshire	±450(DC)	2000
Ontario**	New York	1 x 230	470
		1 x 230	400
		2 x 230	600
		2 x 345	2 300
		2 x 69	132
		2 x 115	200
	Michigan	1 x 230	535
		1 x 230	515
		2 x 345	1 470
	Minnesota	1 x 120	35
Manitoba	North Dakota	1 x 230	150
	Minnesota	1 x 230	175
	Minnesota	1 x 500	1 000
Saskatchewan	North Dakota	1 x 230	150
British Columbia**	Washington	1 x 230	300
		1 x 230	400
		2 x 500	4 300

* 35 MW capacity or over.
** The transfer capability of several lines may not be equal to the mathematical sum of the individual transfer capabilities of the same lines.
*** Actual transfer capability in practice will be different from design capability.

Source: Natural Resources Canada

Table 9.4
Planned International Interconnections

Province/State	Voltage (kV)	Estimated Power transfer Capability (MW)	Completion Date	Status
N.B. - Maine	345	600	1998	Proposed
B.C. -Washington	230	700	1999	Proposed
B.C. -Washington	500	1 000	2003	Proposed

Source: Canadian Electric Utilities

Figure 9.1 Canada's Major Long-Distance Transmission Systems, 1993

Figure 9.2 Major Provincial and International Interconnections, 1993

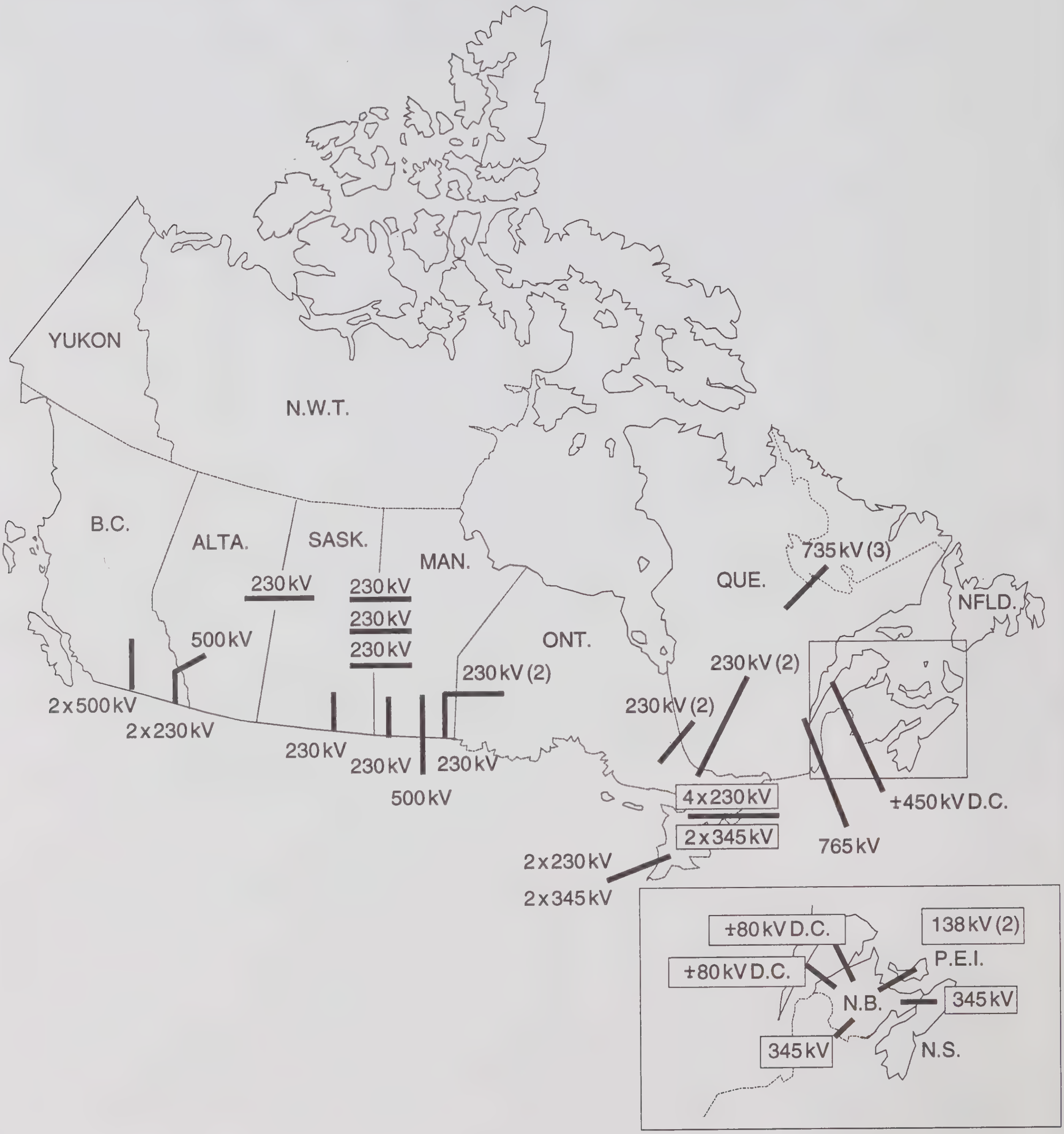


Figure 9.3 System Average Interruption Frequency in Canada, 1993

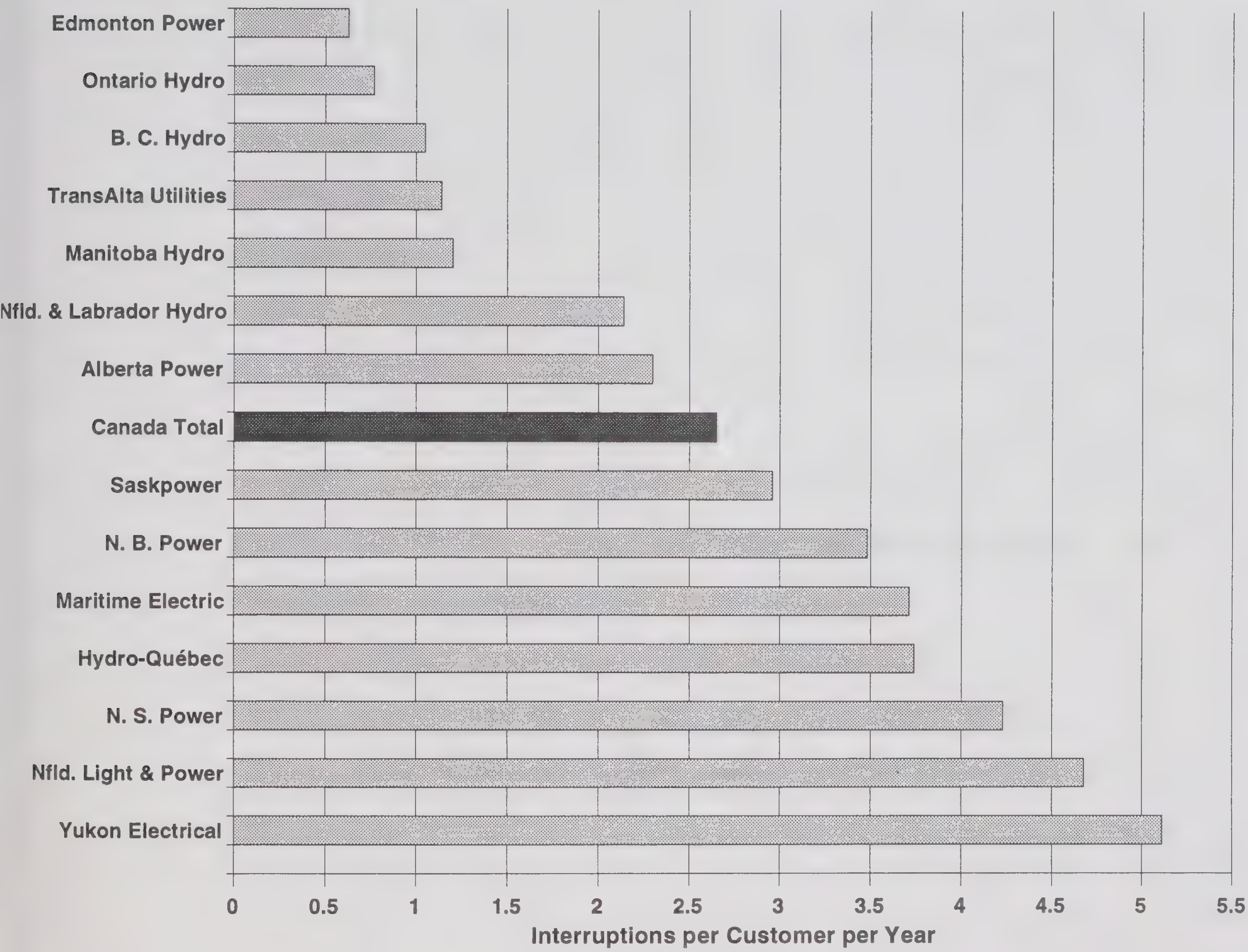


Figure 9.4 System Average Interruption Duration in Canada, 1993

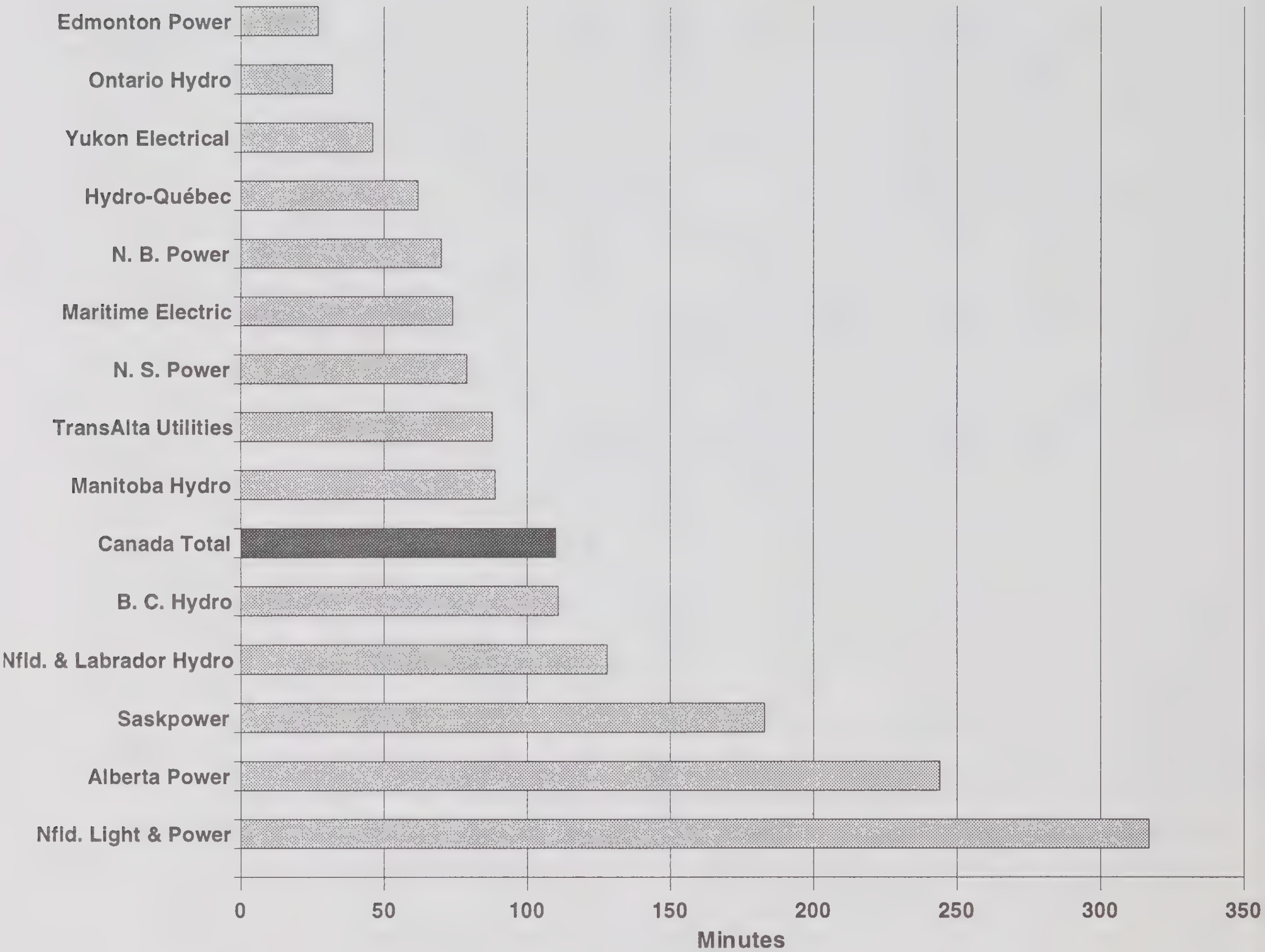
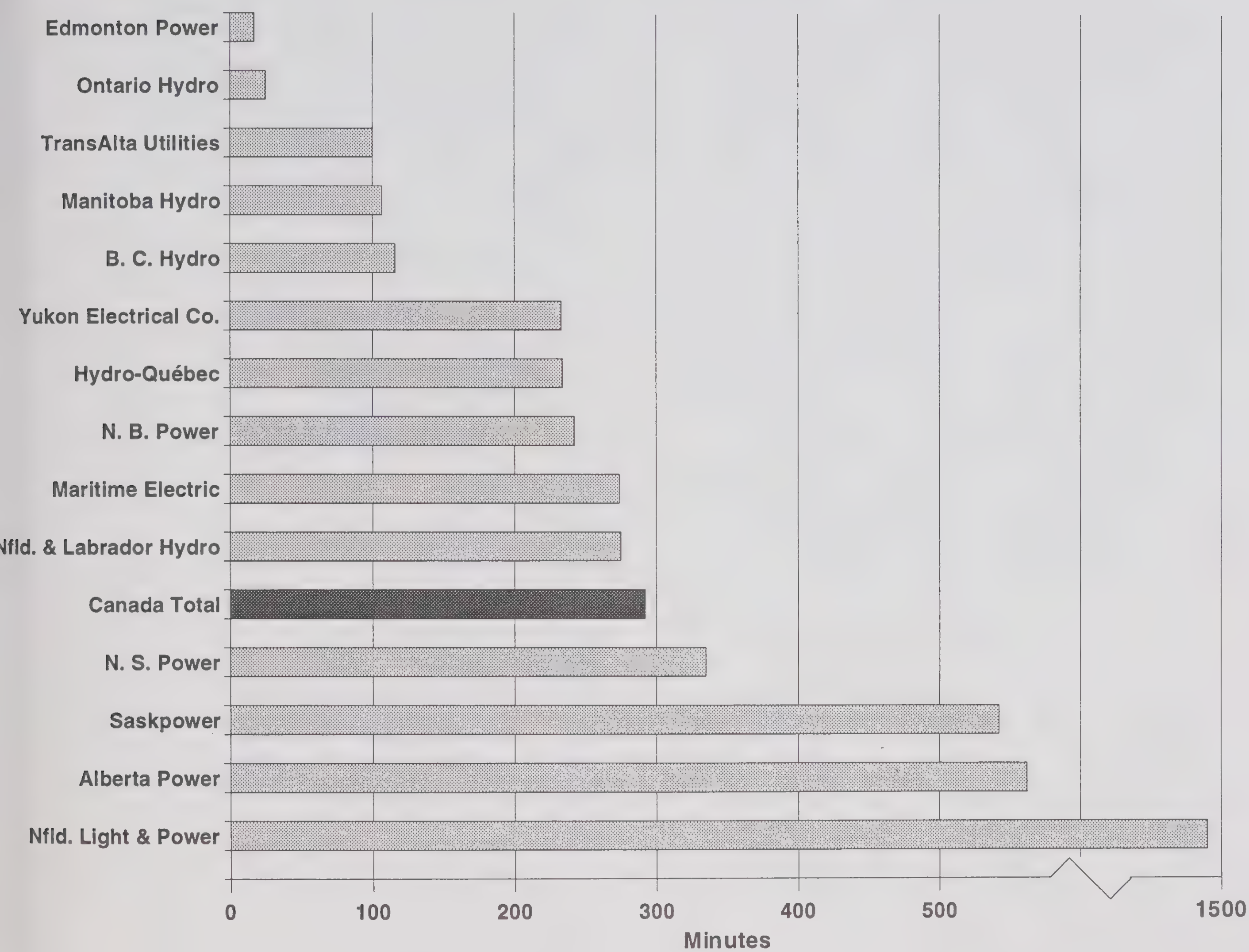


Figure 9.5 Average Interruption Time per Customer per Year, 1993



Electric Utility Investment and Financing

Capital Investment

The electric power industry is one of the most capital intensive industries in our economy. Between 1980 and 1991, the average capital-output ratio for the industry was 6.8. This means that in order to generate one dollar's worth of electricity, about seven dollars must be invested in the electric power industry. This capital-output ratio is very high, compared with 1.2 for total manufacturing industries, and 1.6 for the economy as a whole.

The most capital intensive type of electrical generation is nuclear. It is estimated that the capital cost of nuclear generation, including depreciation, the debt guarantee fee and financing charges, accounts for about 66 per cent of the total cost. The fuel cost accounts for only 11 per cent, and operation and maintenance for 23 per cent. Because of such a cost structure, nuclear energy is inflation proof over its 40-year life-service.

Every year, electric utilities invest in new facilities or upgrade old facilities to meet customer needs. From 1971 to 1993, electric utilities total capital investments increased from about $1.8 billion to $9.6 billion, with an average annual growth rate of 8.1 per cent. If the average annual inflation over this period (6.2%) is removed, the real annual growth rate is 1.9%. Table 10.1 illustrates the capital- intensive nature of electricity generation and its importance in the Canadian economy.

Since 1989, electric utility capital expenditures have been increased significantly, accounting for more than 51 per cent of the total capital investment in the energy sector. This increased investment is probably due to stronger-than-expected domestic demand.

Table 10.2 summarizes capital expenditures in the energy sector. During the period 1972-93, the electric power industry had the largest investment share in the energy sector, with the exceptions of 1984 and 1985, when petroleum and natural gas exploration and production had the largest share. Over the past 22 years, capital investment in the electric power industry totalled about $145 billion (accounting for 47 per cent of total investment in the energy sector).

In 1993, the electric power industry's investment share was 48 per cent of the total for the energy sector. This is a substantial decrease from 53 per cent in 1992 and is the lowest in the past five years, indicating that the electric power industry may be returning to the low investment period of the 1980s because of slow growth of demand and surplus capacity (Table 10.1).

Of the total $145 billion capital investment between 1972 and 1993, about 56 per cent was invested in generation, 19 per cent in transmission, 13 per cent in distribution, and 12 per cent in others (Table 10.3). This represents a fairly large investment in generation for the period, since a traditional rule-of-thumb states that capital investment in generation normally accounts for 50 per cent of total investment in the industry. Figure 10.1 shows electric utility capital investment by function in 1993.

Table 10.4 reports the capital investment for 15 major electric utilities in 1992 and 1993. With the exceptions of N.B. Power, Hydro-Québec, Yukon Energy Corporation and the Northwest Territories Power Corporation, all major utilities reduced their capital investment in 1993. Hydro-Québec was the largest money spender, accounting for 47 per cent of total utility capital investment in 1993, most of which was related to the on-going construction of the James Bay Phase II hydroelectric projects.

Capital Financing

To build a power project, an electric utility normally uses its reserve funds to finance a portion of the construction costs (self-financing), with the larger portion of the costs usually financed by international and domestic debt borrowing (debt-financing) and bond and/or stock issues (equity-financing). Electric utilities regularly have to pay a fixed interest charge on debt- financing, while the payments on equity-financing, especially stock issues, are determined by the operation of the utility.

Canada's electric utilities rely heavily on foreign sources to finance their capital investment because of a relatively small financial market within the country. However, the degree of dependence on foreign financing has been reduced substantially since 1986. Some major electric utilities have tried to finance their power projects mainly from domestic financial markets in order to avoid foreign exchange losses. In 1985, foreign financial sources accounted for 52 per cent of the existing total long-term debt financing. This percentage was reduced to 46 in 1986, 43 in 1987, 40 in 1988, and 35 in 1990. As of December 31, 1993, the total outstanding long-term debt of major electric utilities in Canada was about $88 billion. Of this total, about 64 per cent (or $56 billion) was borrowed on the domestic market, and 36 per cent (or $32 billion) on international markets. Of the $32 billion borrowed internationally, it is estimated that 85 per cent (or $27 billion) was raised in the United States; 4.4 per cent (or $1.4 billion) in the United Kingdom; 4.2 per cent (or $1.3 billion) in Germany; 3 per cent (or $997 million) in the Switzerland; and 2 per cent (or $711 million) in Japan (Table 10.5).

In Canada and the United States, publicly owned electric utilities depend mainly on debt-financing. Investor-owned utilities, on the other hand, rely much more on equity-financing. Table 10.6 indicates that in 1993, Canadian publicly owned electric utilities had debt ratios ranging from 68 per cent to 93 per cent. With the exception of Manitoba Hydro, all publicly owned utilities have strong financial positions. The debt ratios for investor-owned utilities ranged from 38 per cent to 61 per cent, indicating they are also financially sound.

High debt ratios, similar to those of Canadian publicly owned utilities, were also common among government-owned utilities in the United States. As Table 10.6 indicates, the Power Authority of the State of New York, the Tennessee Valley Authority, and the Bonneville Power Administration had debt ratios of 74, 88 and 100 per cent respectively. The selected American investor-owned utilities had debt ratios ranging from 39 per cent to 56 per cent in 1991. In general, the financial position of American investor-owned utilities is not as good as that of their Canadian counterparts.

Tables and figures referred to in this chapter are on the following pages.

Tables & Figures

Table 10.1
Electric Utility Capital Investment, 1971-1993

	Investment in electric power industry ($ million)	Utility investment as a percentage of total energy investment	Utility investment as a percentage of total investment in the economy	Utility investment as a percentage of GDP
1971	1 747	52	8	1.8
1972	1 754	49	7	1.6
1973	2 244	53	8	1.8
1974	2 753	53	8	1.8
1975	3 957	58	9	2.3
1976	4 229	55	9	2.1
1977	4 884	56	10	2.2
1978	5 936	58	11	2.5
1979	6 364	53	10	2.3
1980	6 109	42	8	2.0
1981	7 319	40	9	2.1
1982	8 408	39	10	2.2
1983	7 770	42	10	1.9
1984	6 340	37	8	1.4
1985	5 727	34	6	1.2
1986	5 618	41	6	1.1
1987	5 946	45	6	1.1
1988	6 971	44	7	1.2
1989	8 458	50	6	1.3
1990	10 291	52	8	1.5
1991	11 826	50	9	1.7
1992	10 917	53	9	1.6
1993	9 647	48	8	1.4

Source: Natural Resources Canada

Table 10.2
Investment in Energy-Related Industries, 1972-1993

Year	Petroleum and Natural Gas: Exploration and Production	Petroleum and Natural Gas: Refining and Marketing	Petroleum and Natural Gas: Natural Gas Processing Plants & Distribution	Pipelines	Electric Power	Coal Mines & Products	Uranium Mines	Drilling Contractors	Total
				(millions of dollars)					
1972	666	351	272	447	1 754	42	11	24	3 567
1975	1 390	595	341	362	3 957	123	30	27	6 825
1980	5 745	502	698	602	6 109	306	277	198	14 437
1985	8 187	681	942	665	5 727	475	160	80	16 917
1986	5 401	723	782	587	5 618	434	144	30	13 724
1987	4 415	1 052	746	503	5 946	338	113	13	13 126
1988	5 590	1 135	875	829	6 971	345	139	17	15 901
1989	4 310	1 433	997	1 183	8 458	1	105	14	16 811
1990	4 751	1 382	1 112	1 817	10 291	8	138	12	19 841
1991	6 084	1 129	1 537	2 546	11 826	398	45	41	23 606
1992	4 607	722	1 506	2 432	10 917	177	80	34	20 476
1993	6 488	433	1 291	2 022	9 647	289	115	40	20 323

Source: Natural Resources Canada

Table 10.3
Capital Investment by Function, 1972-1993

Year	Generation	Transmission	Distribution	Other	Total
		(millions of current dollars)			
1972	1 020	432	229	73	1 754
1975	2 460	616	547	334	3 957
1980	3 580	1 114	703	712	6 109
1985	2 941	836	1 008	942	5 727
1986	3 214	815	989	600	5 618
1987	2 774	1 200	1 039	933	5 946
1988	3 137	1 812	1 115	907	6 971
1989	4 313	2 115	1 269	761	8 458
1990	6 147	2 074	1 235	835	10 291
1991	6 340	2 551	1 398	1 417	11 826
1992	5 676	2 402	1 310	1 529	10 917
1993	4 910	1 507	2 163	1 067	9 647

Source: Natural Resources Canada

Table 10.4
Capital Investment by Major Electric Utility

	1992	1993	Year-Over-Year Change
	(millions of current dollars)		
Newfoundland and Labrador Hydro	29	25	-4
Newfoundland Light & Power	46	33	-13
Maritime Electric Co. Ltd.	14	12	-2
Nova Scotia Power	172	132	-40
NB Power	518	530	12
Hydro-Québec	4 127	4 030	3
Ontario Hydro	4 000	2 288	-1 712
Manitoba Hydro	356	300	-56
Saskatchewan Power	245	229	-16
Alberta Power	119	102	-17
Edmonton Power	110	215	105
TransAlta Utilities	240	169	-71
B.C. Hydro	607	440	-167
Yukon Energy Corporation	6	11	5
Northwest Territories Power Corporation	9	19	10
Canada	**10 598**	**8 537**	**-2 061**

Source: Natural Resources Canada

Table 10.5
Major Electric Utility Long-Term Debt and Sources of Financing, 1993

	Long-term Debt	Sources of Long-term Debt Financing	
	($ millions)	Domestic (%)	Foreign (%)
Newfoundland and Labrador Hydro	1 367	59	41
Newfoundland Light & Power	217	100	0
Maritime Electric Co. Ltd.	52	100	0
Nova Scotia Power	1 300	75	25
NB Power	3 234	74	26
Hydro-Québec	33 204	44	56
Ontario Hydro	31 848	82	18
Manitoba Hydro	4 372	31	69
Saskatchewan Power	1 783	65	35
Alberta Power	836	100	0
Edmonton Power	350	100	0
TransAlta Utilities	1 423	100	0
B.C. Hydro	7 680	74	26
Yukon Development Corporation	64	100	0
Northwest Territories Power Corp.	67	100	0
Canada	**87 797**	**64**	**36**

Source: Natural Resources Canada

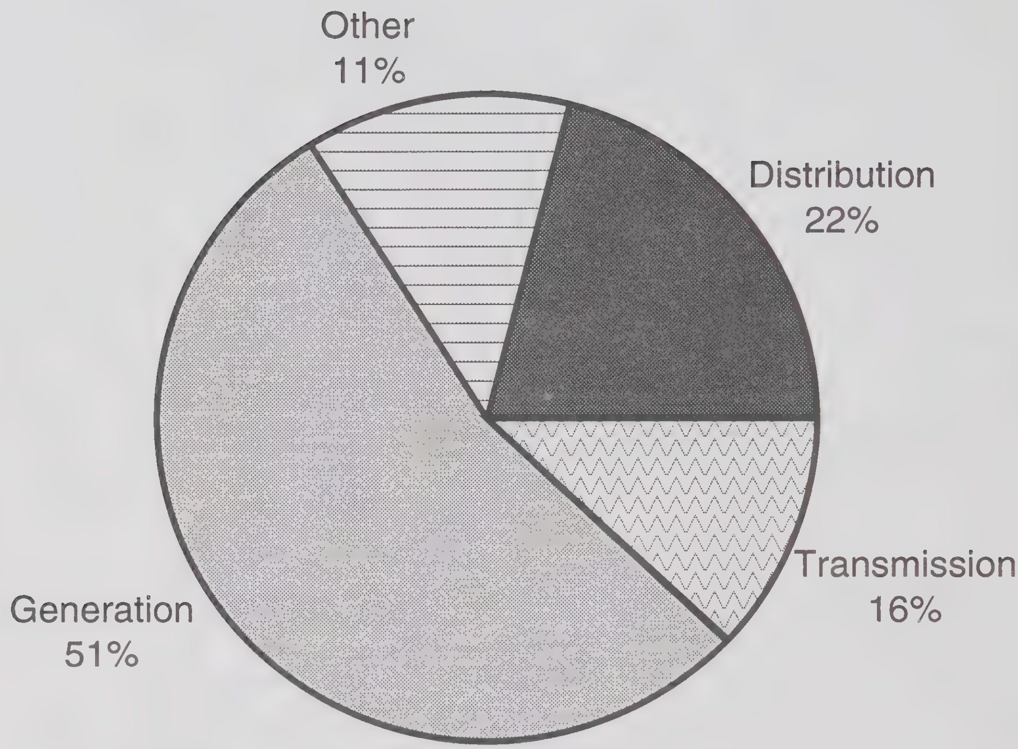
Table 10.6
Comparison of Canadian and U.S. Electric Utility Debt Ratios, 1988-1993

	1988	1989	1990	1991	1992	1993
			(per cent)			
CANADA						
Publicly Owned Utilities						
Newfoundland and Labrador Hydro	83	82	84	74	83	82
NB Power	83	82	83	82	87	89
Hydro-Québec	74	74	75	76	76	76
Ontario Hydro	83	83	83	84	84	92
Manitoba Hydro	95	95	94	94	95	93
Winnipeg Hydro	75	69	68	64	68	73
Saskatchewan Power	81	74	69	67	68	68
Edmonton Power	75	76	73	73	74	73
B.C. Hydro	81	80	79	75	75	78
Investor-Owned Utilities						
Newfoundland Light & Power	44	48	43	41	46	49
Maritime Electric Co. Ltd.	47	47	39	44	43	44
Nova Scotia Power*	99	97	96	95	68	61
TransAlta Utilities Corporation	39	41	45	40	40	38
Alberta Power	38	41	46	42	46	44
UNITED STATES						
Publicly Owned Utilities						
Tennessee Valley Authority	83	81	84	84	88	88
Bonneville Power Administration	100	100	100	100	100	100
Power Authority of the State of New York	69	68	70	75	74	-
Investor-Owned Utilities						
Boston Edison Company	50	52	55	54	51	-
Northeast Utilities	54	52	51	52	60	-
Consolidated Edison Company of New York	37	38	39	39	39	-
Niagara Mohawk Power Corporation	55	57	57	56	56	-
American Electric Power Company	52	47	50	50	51	-
Northern States Power Company	42	41	41	40	41	-
Washington Water Power Company	51	49	47	49	45	-
Pacific Gas and Electric Company	49	48	48	49	48	-

*Privatized in 1992.

Source: Natural Resources Canada

Figure 10.1 Capital Investment by Function, 1993



Total Investment: $9.6 billion

Chapter 11

Costing and Pricing

Electricity Supply Costs

During the period 1962-1993, increases in the cost of building electric power stations, transmission lines, and distribution systems were relatively small.

The unit cost of supplying additional electricity increased rapidly during the period 1973-81 [which coincided with the first (1973) and second (1979) oil crises (see Table 11.1)]. There were two key reasons for the rapid increases in the cost of electricity: the high rate of inflation (as measured by the Consumer Price Index (CPI) or the Gross Domestic Product (GDP) deflator), with an average annual increase of 9.5 per cent; and the increased cost of fossil fuels, with an average annual increase of 15 per cent. In general, high levels of inflation affect the electric utility industry by increasing the cost of facility constructing and by increasing the cost of the funds required to finance the construction.

The average interest rate on long-term utility debt for the period 1962-93 is also shown in Table 11.1. Interest rates started to rise after the first oil crisis and reached a peak of 16.3 per cent in 1981. After this, they dropped steadily to about 10.8 per cent by 1991, 9.9 per cent by 1992, and 8.8 per cent by 1993.

Since 1982, construction cost increases have moderated significantly. Adjusted for inflation, recent increases in the supply cost of electricity have been very small or negative.

In 1991, the federal sales tax was removed from items where it had previously been deemed applicable. The Goods and Services Tax (GST) is not applied to any item within electric utilities construction costs; if utilities pay GST on their construction inputs, they are later reimbursed.

Table 11.2 summarizes the unit costs of the various fossil-fuels used for electricity generation. Like construction costs, unit fuel costs increased substantially during the period 1973-81. It is estimated that the cost of natural gas increased annually by an average of 30 per cent, petroleum by 23 per cent, eastern coal by 19 per cent, and western coal by 15 per cent.

Unit fossil-fuel costs reached a peak in 1985 but began to decline in 1986 with the collapse of world oil prices. In 1992, unit costs of electricity generation from petroleum and natural gas decreased by about 14 and 15 per cent , respectively. This was due to low demand for fuel oil and natural gas in 1992.

The unit cost of using coal for electricity generation for the western provinces also decreased by 3 per cent, which was mainly attributed to coal price decreases of 3 and 11 per cent in Alberta and Saskatchewan. However, the unit cost from coal-fired generation in the eastern provinces increased by 4 per cent resulting from an increase of imported coal prices.

The unit cost of electricity generated from coal varies between regions of the country depending upon the type of coal used, its source and the quantity required. The unit fuel cost of electricity generated from western Canadian coal increased from 1.11 mills per kWh in 1969 to 5.88 mills per kWh in 1992. In the same period, the cost of coal-fired generation in eastern Canada increased from 3.46 mills per kWh to 23.21 mills per kWh. This large cost-difference between the two regions is mainly due to the fact that coal used for electricity generation in western Canada is produced domestically, while a large proportion of the coal used in eastern Canada is imported.

Over the last 17 years, nuclear-generated electricity has had competitive unit fuel costs in Canada. In 1992, it cost 5.18 mills per kWh, compared with an average of 26.80 mills for

petroleum, 18.83 mills for natural gas, 23.21 mills for eastern coal and 5.88 mills for western coal. However, in terms of percentage increases, the unit fuel cost of using uranium for electricity generation increased at an average annual rate of 9.9 per cent during the period 1976-92, compared with 4.5 per cent for eastern coal, 4.4 per cent for western coal, 3.5 per cent for petroleum and 3.0 per cent for natural gas.

Electricity Pricing

In Canada, electric utilities price electricity at the average cost of production, which is generally lower than the marginal cost of production. Although marginal-cost pricing of electricity has the advantage of achieving economic efficiency (i.e. closing the cost-price gap), this pricing method has not been adopted by the provinces and electric utilities because of the complexities of marginal costing and because average costing has provided low-cost electricity and enhanced opportunities for regional economic development.

Rate design has evolved since the first oil crisis of 1973, and several alternatives to marginal-cost pricing have been implemented. For example, declining block rates for residential users (i.e. the more you use the less you pay) have been replaced by a uniform rate in Newfoundland, Prince Edward Island, Saskatchewan, Alberta and the Yukon; seasonal time-of-use rates were introduced in Ontario in January 1989; and automatic adjustment clauses for the escalation of fuel costs have been built into the rate design of those utilities that operate baseload oil-fired stations. The objective of all of these rate design efforts is to close the cost-price gap. Rate methodologies will continue to evolve to meet the changing needs of customers.

Table 11.3 presents annual electricity rate increases for major electric utilities across Canada over the past 10 years. In 1993, Ontario Hydro had the highest rate increase with 7.9 per cent, followed by the Yukon Energy Coroporation, 6.8 per cent and Alberta Power, 5.1 per cent. A weighted average for Canada was about 3.7 per cent, compared with 7.2 per cent in 1992. Increases were higher than the CPI, which registered increases of 1.5 per cent in 1992 and 1.8 per cent in 1993.

The 7.9 per cent rate increase in Ontario was attributed to the completion of the Darlington Nuclear Station (4x881 MW). The last two units were commissioned in February and July 1993. The total rate increase for Ontario during the past 3 years was more than 28 per cent.

The average revenue from electricity sales for each province is provided in Table 11.4. Because electricity rates are regulated by provincial governments and are intended to cover a utility's costs, rate increases tend to parallel the rate of inflation. The average annual growth in unit revenue for Canada as a whole was 4.1 per cent during the period 1982-92. The national inflation rate, as measured by the CPI, was 4.2 per cent over the same period.

Figure 11.1 illustrates the movement of the electricity, oil and natural gas components of the CPI, as well as the CPI itself. It indicates that since the collapse of world oil prices in 1986, the electricity price component has increased in line with the CPI, while natural gas price indices have declined despite rising inflation. The oil price indices have also decreased since 1986, but have started to rise since 1990.

Income statements for the major electric utilities are summarized in Table 11.5. In 1993, 16 major electric utilities in Canada had total operating revenues of $24.1 billion and a net loss of $1.9 billion, compared with a net income of $2.0 billion in 1992. This net loss was mainly due to Ontario Hydro's net loss of $3.6 billion, resulting from corporate restructuring in 1993.

Hydro-Québec had the largest net income of $761 million, followed by B.C. Hydro with $394 million. Hydro-Québec's net income for 1992 was $724 million.

Electricity costs differ across the country primarily because of differences in generation mix, the size and location of the utility and its market, indigenous resources and geography. Table 11.6 gives typical monthly electricity bills for selected Canadian cities as of January 1994. Winnipeg had the lowest electricity costs in the residential and industrial sectors, and Vancouver in the commercial sector.

Tables and figures referred to in this chapter are on the following pages.

Tables & Figures

Table 11.1
Inflation, Interest Rates and Construction Costs, 1962-1993

	Average Interest Rate	Increase in Construction Costs					
		Hydro	Steam	Nuclear	Transmission	Distribution	CPI
				(per cent)			
1962	5.4	2.8	-	-	1.0	1.8	1.2
1963	5.5	3.3	-	-	1.5	0.4	1.7
1964	5.5	3.2	-	-	0.0	2.2	1.8
1965	5.7	5.0	-	-	5.7	2.2	2.5
1966	6.4	6.2	-	-	4.1	5.1	3.7
1967	6.7	3.6	1.1	-	5.2	1.6	3.5
1968	7.8	4.2	2.8	-	2.9	1.2	4.7
1969	8.6	5.7	6.8	-	4.4	4.3	4.5
1970	9.3	6.6	7.4	-	5.0	7.5	3.3
1971	8.5	4.6	6.0	-	5.5	3.5	2.9
1972	8.4	6.3	6.1	6.9	6.3	4.4	4.8
1973	8.6	9.2	9.2	9.5	8.8	9.4	7.6
1974	10.2	18.8	20.5	19.2	19.2	20.4	10.9
1975	10.7	14.3	13.4	13.1	17.6	12.3	10.8
1976	10.4	8.9	10.0	9.7	7.3	5.7	7.5
1977	9.6	5.9	7.9	7.5	7.8	6.6	8.0
1978	10.1	7.7	8.7	8.0	8.0	7.4	9.0
1979	10.9	8.7	11.0	12.7	14.8	13.5	9.2
1980	13.3	10.0	11.6	22.0	13.6	14.0	10.2
1981	16.3	13.7	11.9	11.4	11.3	9.1	12.5
1982	15.9	7.2	6.8	5.3	4.8	9.3	10.8
1983	12.7	4.6	4.1	5.0	3.8	4.1	5.8
1984	13.5	3.2	2.8	0.1	5.3	4.4	4.4
1985	11.7	1.7	3.8	4.8	0.9	5.2	4.0
1986	10.4	4.1	3.5	3.5	2.1	2.4	4.1
1987	10.7	4.1	3.0	1.9	3.8	3.1	4.4
1988	10.9	4.0	5.7	2.8	9.2	6.1	4.1
1989	10.8	3.4	4.2	5.1	3.6	3.8	5.0
1990	11.9	4.5	3.6	3.3	2.6	3.2	4.8
1991	10.8	6.1	2.0	1.8	2.2	-0.8	5.6
1992	9.9	2.7	1.7	-	-1.2	2.3	1.5
1993	8.8	2.7	1.0	-	3.1	2.9	1.8

Source: Interest Rates - McLeod Young Weir Limited's average corporate bonds yield. Construction costs and CPI-Statistics Canada publications 62-007 and 62-001

Table 11.2
Cost of Fuel for Electricity Generation, 1969-1992

	Eastern Coal*	Western Coal**	Petroleum	Natural Gas	Uranium	Total Fuels
			(mills/kWh)			
1969	3.46	1.11	4.97	2.54	-	3.24
1970	3.60	1.38	5.68	2.47	-	3.25
1971	4.20	1.28	5.98	3.15	-	3.46
1972	4.32	1.34	6.41	3.93	-	3.42
1973	4.65	1.43	7.06	3.74	-	3.13
1974	5.38	1.54	11.36	5.18	-	4.10
1975	8.64	2.07	12.87	7.17	-	6.16
1976	11.43	2.97	15.38	11.74	1.14	8.11
1977	11.89	3.20	19.01	15.21	1.34	8.40
1978	13.12	2.88	21.22	16.19	1.61	8.82
1979	16.50	3.11	23.93	15.22	1.65	9.62
1980	18.22	3.75	26.22	15.47	2.65	10.69
1981	20.48	4.83	40.77	23.22	2.68	12.22
1982	22.61	5.76	44.88	30.16	2.87	14.04
1983	23.71	5.96	57.27	31.17	3.25	13.20
1984	24.85	5.94	65.11	34.15	3.84	13.64
1985	26.07	6.59	68.02	31.81	4.74	13.54
1986	25.88	5.13	45.15	27.11	4.52	10.70
1987	25.07	5.84	37.22	22.20	4.77	11.63
1988	22.05	5.51	27.53	25.17	4.53	10.52
1989	20.96	5.63	29.08	18.78	4.62	11.16
1990	22.83	5.87	32.93	21.67	4.88	11.41
1991	22.32	6.60	31.24	22.20	5.01	10.90
1992	23.21	5.88	26.80	18.83	5.18	10.97

* Nova Scotia, New Brunswick and Ontario.
** Alberta, Saskatchewan and Manitoba.

Source: Calculated from Electric Power Statistics, Statistics Canada, catalogue 57-202, various issues

Table 11.3
Average Annual Electricity Rate Increases, 1984-1993

	Rate Changes (%): Average of all Customer Classes									
	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
Nfld. & Labrador Hydro	-	-	-1.7	-	-	1.0	8.2	1.6	3.8	0.0
Nfld. Light & Power	-	-	8.7	3.0	-1.1	2.0	12.5	0.8	5.2	0.3
Maritime Electric Co.Ltd.	-	3.7	-3.8	-	-1.3	-	5.5	5.3	2.6	1.2
Nova Scotia Power	-	-	-	-	-	6.3	2.5	5.0	2.1	1.8
NB Power	6.2	4.6	-	-	-	-	-	4.4	5.0	0.0
Hydro-Québec	4.0	4.0	5.4	4.9	3.9	4.7	7.4	7.0	3.5	1.5
Ontario Hydro	7.5	8.6	4.0	5.0	4.7	5.3	5.9	8.6	11.8	7.9
Manitoba Hydro	7.9	5.0	2.8	9.7	4.5	6.0	4.0	3.5	3.5	0.0
Saskatchewan Power	9.2	-	7.5	7.5	6.1	3.9	-1.9	-0.6	4.0	4.0
Edmonton Power	5.0	6.7	0	3.0	1.9	-	-	3.0	8.0	3.3
TransAlta Utilities	-	1.7	6.1	-1.8	-1.0	5.5	-1.1	12.0	3.0	2.0
Alberta Power	-	-4.3	-8.6	-5.0	14.5	2.6	3.7	17.0	7.0	5.1
B.C. Hydro	6.5	3.8	1.8	-	-	3.0	1.5	3.0	7.0	3.9
Yukon Energy	-	-	0.7	-	-	-	4.0	11.3	-2.3	6.8
NWT Electric	-	-	-	-	-	-	9.5	0	6.0	0.0
Weighted Canada	**-**	**6.2**	**4.1**	**4.2**	**3.5**	**4.3**	**4.9**	**6.8**	**7.2**	**3.7**

Source: Natural Resources Canada

Table 11.4
Average Revenue from Electricity Sales by Province, 1983-1992

	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
	(current cents/kWh)									
Newfoundland	3.7	3.9	4.7	3.9	4.0	4.0	4.1	4.4	4.9	4.7
P.E.I.	12.3	12.8	12.9	11.5	10.3	10.8	10.2	10.8	11.3	11.7
Nova Scotia	6.9	7.5	7.3	6.9	6.8	7.0	6.9	7.2	7.4	7.7
New Brunswick	5.4	5.5	5.8	5.5	5.5	5.3	5.5	5.2	5.6	5.6
Quebec	3.4	3.4	3.5	3.4	3.4	3.6	3.9	4.3	4.6	4.8
Ontario	3.9	4.2	4.5	4.5	4.9	5.1	5.4	5.7	6.3	7.0
Manitoba	3.1	3.4	3.6	3.6	3.9	4.0	4.1	4.3	4.5	4.7
Saskatchewan	4.2	4.5	4.8	5.0	5.5	5.8	6.1	6.0	5.9	5.9
Alberta	5.2	5.4	5.4	5.4	5.3	5.0	4.9	5.2	5.2	5.2
British Columbia	3.8	4.1	4.4	4.2	4.2	4.2	4.2	4.3	4.7	4.6
Yukon	8.3	8.6	9.0	7.8	7.4	7.7	7.1	7.3	7.9	8.0
N.W.T.	17.9	16.7	16.3	15.9	17.6	17.7	20.7	19.9	21.0	22.3
Canada	**3.9**	**3.9**	**4.1**	**4.3**	**4.2**	**4.5**	**4.8**	**5.0**	**5.3**	**5.6**

Source: Statistics Canada publication 57-202

Table 11.5
Major Electric Utilities' Statements of Income, 1993

	Total Revenue	O&M	Fuel Costs	Power Pur-chased	Depre-ciation	Taxes	Interest	Ex-change Losses	Other Costs	Net Income
	(millions of current dollars)									
Nfld. & Labrador Hydro	373	108	43	1	42	-	148	-	7	24
Nfld. Light & Power	350	58	-	191	27	20	22	-	3	29
Maritime Elec. Co. Ltd.	81	33	-	23	7	5	5	-	-	8
Nova Scotia Power	738	156	247	-	71	34	161	-	(24)	93
NB Power	896	271	145	55	130	-	245	-	26	24
Hydro-Québec	7 036	1 800	-	291	1 020	650	2 483	31	-	761
Ontario Hydro	8 363	2 060	911	260	1 506	286	3 330	-	3 614	(3 604)
Manitoba Hydro	823	237	-	7	136	45	422	-	-	(24)
Winnipeg Hydro	117	31	-	51	4	-	11	-	6	14
Saskatchewan Power	790	234	124	-	130	44	193	-	(16)	81
Alberta Power	569	124	77	(9)	83	100	87	-	31	76
Edmonton Power	411	101	-	107	45	36	133	-	(41)	30
TransAlta Utilities	1 313	243	83	-	224	229	140	-	-	394
B.C. Hydro	2 090	410	384	-	295	170	679	-	181	152
Yukon Dev. Corp.	15	8	-	-	2	-	2	-	-	3
N.W.T. Power Corp.	93	40	33	-	9	-	9	-	(2)	4
Canada	**24 058**	**5 914**	**2 047**	**977**	**3 731**	**1 619**	**8 070**	**31**	**3 604**	**(1 930)**

Source: Obtained from electric utilities' annual reports, 1993

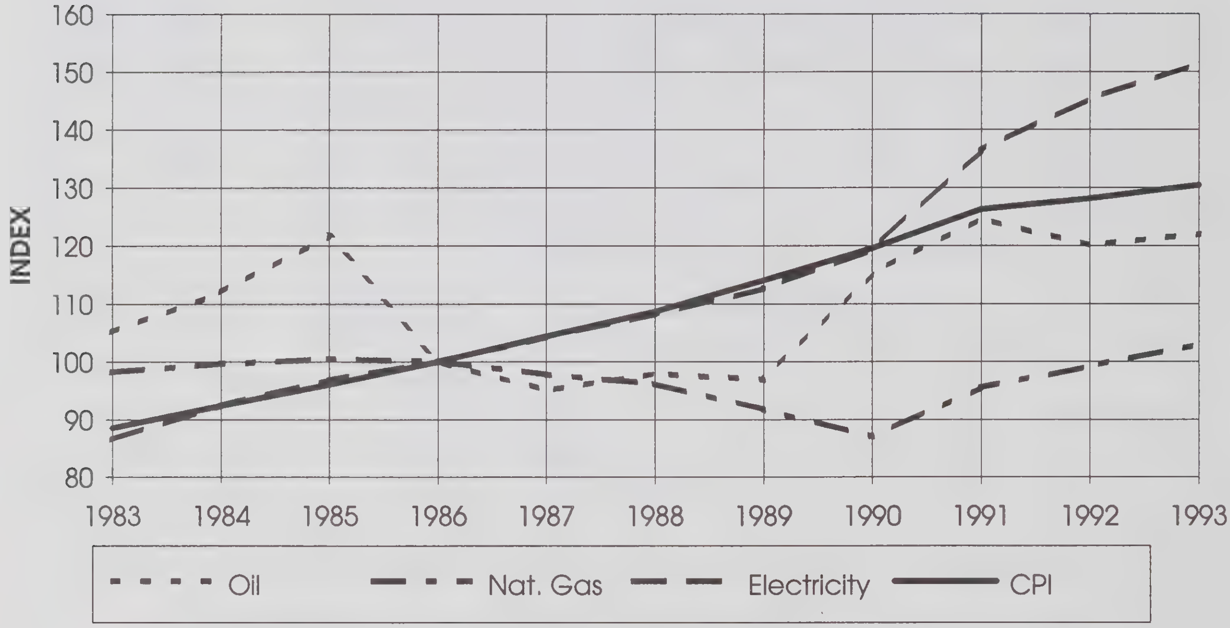
Table 11.6
Monthly Electricity Costs, January 1994 (Dollars)*

Sector:	Residential	Commercial	Industrial
Billing Demand (kW):	-	100	1000
Consumption (kWh):	1000	25 000	400 000
St. John's	86	2 581	24 355
Charlottetown	122	3 223	35 723
Halifax	97	2 742	26 982
Fredericton	80	2 310	22 820
Montreal	66	2 328	21 715
Ottawa	79	2 051	29 465
Toronto	101	2 826	34 500
Winnipeg	63	1 793	19 092
Regina	84	2 772	33 221
Calgary	71	2 139	22 400
Vancouver	67	1 683	19 976
Whitehorse	86	2 661	-
Yellowknife	141	3 546	-

* Bills computed include sales tax, discounts and subsidies.

Source: Natural Resources Canada

Figure 11.1 Price Indices, 1983-1993 (1986 = 100)



Electricity Outlook

Forecasts of electrical energy demand (kilowatt-hours) and peak load (kilowatts) are the starting points in the electric utility planning cycle. Forecasts of peak and energy demands are essential to ensure that sufficient generating capacity is available when it is needed. As the lead times required to add new generating capacity have lengthened, and the costs of new capacity have risen, the importance of forecasting has increased substantially.

The demand for electricity (both peak and energy) is affected by many variables. Some of them are easily identified while others are not; some can be measured, others cannot; in some cases their influence on the electricity load is rather straightforward, but in most cases the relationship is more subtle.

At the same time, forecasting electricity demand has become more difficult because of greater uncertainties about future input variables. Uncertainties associated with input variables, such as future electricity prices, fuel prices, economic growth, population, weather, efficiency standards, regulatory changes and other policy changes, create uncertainties in the forecasts of electricity demand. These uncertainties are in addition to the uncertainties inherent in the methodologies themselves used by electric utilities.

Forecasts of Electrical Energy Demand

As mentioned earlier, there are many factors affecting electrical energy demand. However, in the long-run, electricity demand will be mainly determined by economic and demographic activities. The economic activity is generally recognized as the most appropriate variable for explaining electricity demand. Slowdown or expansion of the economy plays a key role in determining electricity use. An increase or decrease of population will affect the formulation of households which, in turn, will also influence electricity use.

Economic and population growth in Canada over the next 17 years are expected to be significantly lower than the previous 33 years. It is estimated that the real Gross Domestic Product will grow at an average of only 2.5 per cent for the period 1993-2010, much less than the historical average of 3.9 per cent achieved during the period 1960-1993. Population is expected to grow at an average of 1.1 per cent for the period 1993-2010, less than the 1.3 per cent registered during the same period 1960-1993. In addition, it is expected that the country's economic structure will not shift greatly over the same period from predominantly service-producing industries to goods-producing industries. In general, goods-producing industries consume more electricity than those producing services. Demand-side management is expected to have greater emphasis in future electrical planning. Because of these expectations, electricity demand is projected to grow at a slower rate.

Table 12.1 summarizes electricity demand forecasts for the ten provinces and two territories. The projections of electrical energy demand within the service areas of the major electric utilities were prepared by the major utilities and provided to Natural Resources Canada in March 1994. Electricity demand for smaller utilities and industrial establishments was projected by the National Energy Board (NEB). The Electricity Branch of Natural Resources Canada (NRCan) combined these two sources of forecasts and produced a total electricity demand forecast for the provinces and territories. As Table 12.1 indicates, electricity demand for Canada as a whole is expected to grow at an average of 1.7 per cent during the period 1993-2010. This projected growth rate

was slightly less than last year's forecast of 1.8 per cent for the same period.

Figure 12.1 compares various forecasts for total electricity demand in Canada. Included for comparison, are the latest forecasts derived from NRCan's Interfuel Substitution Demand Model, the NEB's Supply and Demand Model, and forecasts provided by the major electric utilities. On the basis of the control case, the NEB's projection of electricity demand for the next 17 years is 2.0 per cent annually, compared with the utilities' 1.7 per cent, and NRCan's 1.5 per cent. The difference among these three forecasts is mainly due to different underlying economic assumptions. All of these forecasts, however, are significantly lower than the average annual growth rate of 4.6 per cent achieved during the period 1960-93.

Forecasts of Peak Demand

The operation of an electrical system must meet two basic requirements: to generate enough energy to meet energy demand, and to have enough capacity to satisfy peak demand. All major electric utilities in the ten provinces and two territories have their peak loads in winter. Table 12.2 reports winter peaks projected mainly by the major electric utilities for the period 1993-2010. For Canada as a whole, peak demand is expected to grow at an average annual rate of 1.8 per cent, which is slightly greater than the 1.7 per cent projected for electrical energy demand. This suggests that the load factor for Canada's electrical system will decline slightly from 64.2 to 63.8 per cent during the period 1993-2010.

Forecasts of Generating Capacity

To meet the forecast growth in electricity demand shown in Tables 12.1 and 12.2, total installed generating capacity in Canada is expected to have a net addition of 15 442 MW during the period 1993-2010, with an average annual growth rate of 0.8 per cent (Table 12.3). This level of growth is slightly lower than those levels projected for energy and peak demand growth, reflecting the current surplus capacity situation in most of the provinces.

Table 12.4 presents installed generating capacity by fuel type for the period 1993-2010. Because of public concern about the environment, the capacity share of coal-fired generation is expected to decline significantly from about 18 per cent of the total capacity in 1993 to 15 per cent by the year 2010. On the contrary, the capacity share of hydro is expected to increase significantly at 56 per cent in 1993 to 59 per cent by 2010. Oil-fired generation is mainly reserved for peaking purposes and its capacity share is expected to stabilize at 7 per cent during the period 1993-2010. However, natural gas-fired generation will be used for both peaking and baseload requirements and its capacity share is estimated to increase from 4 per cent to 6 per cent of the total over the same forecast period. The nuclear share is projected to decrease slightly from 14 per cent of the total in 1993 to 12 per cent by 2010 due to the moratorium of the nuclear program in Ontario. Other installed capacity is expected to stablize at 1 per cent in the forecast period 1993-2010.

Figure 12.2 compares various forecasts of total generating capacity in Canada. Between 1993 and 2010, the electric utilities projected new capacity additions of only 15 GW, or about 882 MW per year. Natural Resources Canada projects capacity additions of 14 GW, or 824 MW per year, and the National Energy

Board projects new additions of 22 GW, or 1294 MW per year.

Forecasts of Electricity Generation

To meet both domestic electricity demand (Table 12.1) and export requirements (Table 12.7), the electric utilities have projected total electricity generation for the period 1993-2010 (Table 12.5). It is expected that hydro-based generation will continue to be the most important source of electric energy in Canada, with its share of total electricity production declining by 2 per cent, from 62 per cent in 1993 to 60 per cent in 2010. Coal-fired production is also expected to decrease its market share by 1 per cent, from 15 per cent in 1993 to 14 per cent by 2010, largely because of environmental concerns.

Even though falling world oil prices in recent years have provided electric utilities with an economic incentive to utilize their existing oil-fired stations in the short term, oil prices are not expected to remain low for long. In the long term, oil-fired stations will continue to be used mainly for peaking capacity and to meet energy demand in remote locations. By the year 2010, the share of electricity generated from oil is expected to be stablized at 2.0 per cent of total electricity generation.

In the long term, the use of natural gas for electricity generation is expected to increase to around 8 per cent of the total generation. This is because a great majority of independent power production, such as co-generation, is expected to use natural gas as the input fuel.

The nuclear share of electricity generation is expected to decline from 17 to 14 per cent during the period 1993-2010. The most recent new nuclear capacity comes from the Darlington station in Ontario, which was completed in 1993. With no other nuclear stations under construction, it is anticipated that the nuclear share of electricity generation will decline by the year 2010.

It is worth noting that electric utilities, particularly Ontario Hydro, B.C. Hydro and Hydro-Québec, have projected a considerable amount of electricity to be derived from independent power production. Table 12.6 indicates that electricity generation from other sources, including independent power production, is expected to increase substantially starting in 1995. By the end of 2010, independent power production is expected to account for about 3.4 per cent of total electricity generation, compared with only 0.7 per cent in 1993. It is estimated that about 2.7 per cent of the independent power production share will use natural gas.

A comparison of various forecasts of electricity generation for the period 1993-2010 is presented in Figure 12.3.

Forecasts of Electricity Exports to the United States

Canada and the United States enjoy essentially free trade in electricity: there is little direct government involvement in the contracting process, there are no tariffs, and there is no regulation over imports of electricity. With the North American Free Trade Agreement now in place, other non-trade barriers will be eliminated, gradually permitting an increase of electricity trade between the two countries. Table 12.7 reports electric utilities' projected electricity exports to the United States for the period 1993-2010. B.C. Hydro's projections of electricity exports to the United States are always on the low side because interruptible sales are not incorporated into this forecast.

Forecasts of Fuel Requirements

Forecasts of fuel requirements for the period 1993-2010 are based on the forecasts of energy generation given in Table 12.6. Between 1993 and 2010, electricity generated from coal-fired stations is estimated to increase by 20 per cent, however, coal requirements are expected to increase by only 19 per cent. This is because an increase of coal-fired generation is forecasted to take place particularly in New Brunswick, Nova Scotia, and Saskatchewan, where more efficient coal-fired plants are under construction or will be built. Alberta, which is traditionally a coal user province, is expected to reduce its coal-fired generation between 1993 and 2010, while Ontario will be increasing its coal-fired generation marginally during the same period.

The use of oil for electricity generation is restricted to meeting peak demand and providing electricity to remote communities.

However, the use of natural gas for electricity generation is projected to increase substantially between 1993 and 2010. Major industrial establishments, mainly in Alberta and Ontario, are the largest users. Electric utilities in Alberta and British Columbia also use a substantial amount of natural gas for electricity generation. Independent power producers, such as co-generators, are expected to use natural gas as input fuel in the provinces of Ontario and Quebec.

Nuclear energy is an important component of Canada's electricity supply. However, the use of uranium for electricity generation is expected to decrease during the period 1993-2010,due to the fact that no new nuclear stations are under construction and some existing stations are expected to retire.

Forecasts of Capital Expenditures

Over the next ten years 1994-2003, major electric utilities in Canada are expected to invest about $82 billion in facilities, an average of $8 billion per year. Quebec will be the largest investor, with $49 billion, accounting for 60 per cent of the total. A large share of this capital investment is expected to be spent on the James Bay Phase II and Grande Baleine hydro projects. Ontario is expected to invest only $15 billion in electrical energy, or about 18 per cent of Canada's total. Most of this expenditure will be used for hydro projects due to the completion of the Darlington Nuclear Station in 1993 (Table 12.9).

The electric utilities' capital investments by function are given in Tables 12.10 - 12.13. It is expected that generating facilities will account for 43 per cent of the total for the period 1994-2003, distribution 26 per cent, transmission 16 per cent, and other facilities 15 per cent.

Forecasts of Emissions from Electricity Generation

Electric utilities project that carbon dioxide emissions will continue to decrease until 1995, from 91 million tonnes in 1993 to 89 million tonnes in 1995, due to the reduction of coal use for power generation. It is then estimated to increase gradually to 125 million tonnes by the year 2010. (Figure 12.4). Coal-fired generation is expected to account for 83 per cent of the total, followed by 9 per cent for natural gas, and 8 per cent for oil.

Because of the application of new technologies to reduce emissions, electric utilities project that their sulphur dioxide emissions will be increased by only 3.5 per cent over the period 1993-2010, despite a 20 per cent increase in the use of coal

for electricity generation during the same forecast period. (Table 12.14). The projections of nitrous oxides emissions are shown in Table 12.15.

Tables and figures referred to in this chapter are on the following pages.

Tables & Figures

Table 12.1
Forecasts of Domestic Electrical Energy Demand (GWh)

	1993*	1994	1995	2000	2005	2010	Average Annual Growth Rate 1993-2010 (%)
Newfoundland	10 904	10 364	10 486	11 774	12 365	12 850	1.0
P.E.I.	806	814	839	935	1 032	1 140	2.1
Nova Scotia	9 919	10 128	10 843	11 842	12 707	13 678	1.9
Mew Brunswick	13 873	14 328	14 906	16 324	17 646	19 124	1.9
Quebec	170 153	179 538	185 353	208 521	219 221	228 121	1.7
Ontario	137 483	141 627	141 666	154 571	164 671	175 469	1.4
Manitoba	18 642	18 701	18 866	20 079	21 354	22 987	1.2
Saskatchewan	15 279	15 450	15 841	17 101	18 066	18 823	1.2
Alberta	46 960	48 128	49 409	54 842	60 662	65 900	2.0
British Columbia	58 672	63 232	64 672	75 242	78 442	88 242	2.4
Yukon	335	303	297	300	305	310	-0.5
N.W.T.	584	605	600	635	665	692	1.0
Canada	**483 610**	**503 218**	**513 758**	**572 166**	**610 836**	**647 336**	**1.7**

Table 12.2
Forecasts of Domestic Peak Demand (MW)

	1993*	1994	1995	2000	2005	2010	Average Annual Growth Rate 1993-2010 (%)
Newfoundland	1 907	1 954	1 967	2 209	2 367	2 494	1.6
P.E.I.	143	148	152	166	175	196	1.9
Nova Scotia	1 922	1 975	2 031	2 192	2 310	2 459	1.5
New Brunswick	2 836	2 976	3 034	3 406	3 676	3 959	2.0
Quebec	30 932	34 512	35 433	39 345	41 725	43 935	2.1
Ontario	25 246	24 507	24 790	26 670	28 560	30 050	1.0
Manitoba	3 564	3 663	3 720	4 040	4 355	4 676	1.6
Saskatchewan	2 482	2 589	2 670	2 868	3 005	3 107	1.3
Alberta	6 874	7 223	7 361	8 186	9 027	9 790	2.1
British Columbia	9 988	10 585	10 936	12 745	13 805	15 035	2.4
Yukon	57	60	60	61	62	63	0.6
N.W.T.	89	106	109	115	117	120	1.8
Canada	**86 040**	**90 298**	**92 263**	**102 003**	**109 184**	**115 886**	**1.8**

* Actual data

Source: Canadian Electric Utilities and the National Energy Board

Table 12.3
Forecasts of Installed Generating Capacity by Province (MW)

	1993*	1994	1995	2000	2005	2010	Average Annual Growth Rate 1993-2010 (%)
Newfoundland	7 447	7 450	7 453	7 781	7 836	7 836	0.3
P.E.I.	121	122	122	122	122	122	0.1
Nova Scotia	2 330	2 330	2 380	2 430	2 550	2 715	0.9
New Brunswick	4 478	4 033	4 033	4 141	4 293	4 596	0.2
Quebec	32 280	33 982	34 787	37 537	42 987	43 181	1.7
Ontario	35 951	35 980	35 205	37 937	36 323	36 323	0.1
Manitoba	4 910	5 312	5 312	5 312	6 278	6 173	1.4
Saskatchewan	2 778	3 144	3 187	3 430	3 307	3 457	1.3
Alberta	8 381	8 500	8 564	8 763	9 204	9 212	0.6
British Columbia	12 966	13 041	13 071	14 152	13 401	13 401	0.2
Yukon	134	135	135	146	149	155	0.9
N.W.T.	208	204	204	225	240	255	1.2
Canada	**111 984**	**114 233**	**114 453**	**121 976**	**126 690**	**127 426**	**0.8**

Table 12.4
Forecasts of Installed Generating Capacity by Fuel Type in Canada (MW)

	1993*	1994	1995	2000	2005	2010
Coal	20 130	20 658	19 928	19 869	18 971	19 911
Oil	8 052	8 000	7 957	8 080	8 685	8 667
Natural Gas	4 231	4 125	4 335	5 514	7 188	7 346
Nuclear	15 857	15 857	15 857	15 857	15 857	15 177
Hydro**	62 722	64 560	65 251	66 559	74 554	74 890
Other***	992	1 033	1 125	1 426	1 435	1 435
Total	**111 984**	**114 233**	**114 453**	**121 976**	**126 690**	**127 426**

* Actual data
** Includes 20 MW of tidal power
*** Generating capacity from woodchips and waste gases

Source: Canadian Electric Utilities and the National Energy Board

Table 12.5
Utility Forecasts of Electricity Generation by Province (GWh)

	1993*	1994	1995	2000	2005	2010	Average Annual Growth Rate 1993-2010 (%)
Newfoundland	40 846	41 510	41 514	44 701	44 433	44 272	0.5
P.E.I.	59	35	32	32	32	32	-3.5
Nova Scotia	9 714	9 983	19 681	11 281	12 037	13 046	1.8
New Brunswick	15 112	14 596	15 536	18 804	20 058	21 134	2.0
Quebec	154 443	152 138	158 033	180 021	192 121	203 021	1.6
Ontario	140 708	146 973	143 237	152 102	164 855	164 255	0.9
Manitoba	27 121	26 798	28 946	30 310	35 665	35 067	1.5
Saskatchewan	15 303	15 202	15 648	16 612	17 508	18 268	1.1
Alberta	48 277	49 463	49 837	54 489	58 363	63 487	1.6
British Columbia	58 586	65 189	66 604	72 330	75 170	80 210	1.9
Yukon	335	303	297	300	305	310	-0.5
N.W.T.	584	605	600	635	665	692	1.0
Canada	**511 088**	**524 795**	**530 965**	**581 617**	**621 212**	**643 794**	**1.4**

Table 12.6
Forecasts of Electricity Generation by Fuel Type in Canada (GWh)

	1993*	1994	1995	2000	2005	2010
Coal	75 541	77 293	72 107	81 142	82 927	90 436
Oil	11 054	7 537	9 173	10 529	14 390	14 072
Natural Gas	12 547	15 946	17 139	29 791	43 860	52 920
Nuclear	88 614	95 933	95 826	94 412	94 843	91 472
Hydro**	319 166	323 361	329 127	356 719	376 052	385 748
Other	4 166	4 925	7 593	9 024	9 140	9 146
Total	**511 088**	**524 795**	**530 965**	**581 617**	**621 212**	**643 794**

* Actual data

** Electrical generation from woodchips, waste gases, and non-utility generators.

Source: Canadian Electric Utilities and the National Energy Board.

Table 12.7
Electricity Exports to the United States (GWh)

	1993*	1994	1995	2000	2005	2010
New Brunswick	1 839	1 086	668	2 377	2 317	2 083
Quebec	13 008	9 100	9 500	10 000	10 600	12 000
Ontario	7 157	7 794	3 550	1 295	0	0
Manitoba	7 359	8 698	9 167	7 340	4 086	2 962
Saskatchewan	229	112	88	88	0	0
British Columbia	5 256	5 500	4 900	5 520	3 460	2 300
Canada	**34 848**	**32 290**	**27 873**	**26 620**	**20 463**	**19 345**

Table 12.8
Fuels Required for Electricity Generation in Canada

	Coal (10^3tonnes)	Oil (10^3m^3)	Natural Gas (10^6m^3)	Uranium (tonnes)
1993*	42 791	2 686	3 459	1 619
1994	43 370	2 067	3 353	1 633
1995	42 099	2 314	3 752	1 564
2000	46 866	2 720	4 481	1 584
2005	47 616	3 807	6 139	1 549
2010	51 014	3 849	7 814	1 482

* Actual data

Note: Average heat content for fuels used in electricity generation in Canada are as follows:

Coal (kj/kg): Bituminous = 29 579, Subbituminous = 18 373, Lignitie = 14 839, Total = 20 966.
Oil (kj/litre): Light = 38 403, Heating = 41 799, Diesel = 37 663, Total = 41 393.
Natural Gas (kj/m^3): 38 042
Uranium (kj/g): 690 687

Source: Canadian Electric Utilities and the National Energy Board

Table 12.9
Forecast of Capital Expenditures for Major Electric Utilities (Total)

	1993*	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
	(millions of current dollars)										
Nfld.	59	64	76	72	87	124	83	83	83	83	83
P.E.I.	12	36	11	11	10	9	9	9	9	9	9
N.S.	132	100	101	105	104	105	106	109	110	113	116
N.B.	530	295	250	106	91	93	95	112	112	112	112
Que.	4 030	3 865	4 013	4 161	4 149	4 740	5 077	5 403	5 718	5 833	5 651
Ont.	2 288	2 017	1 794	1 626	1 402	1 437	1 390	1 436	1 227	1 218	1 226
Man.	300	330	342	254	151	215	256	278	303	222	194
Sask.	229	260	311	201	214	213	186	186	143	170	147
Alta.	487	380	355	331	282	290	298	346	518	505	487
B.C.	440	537	518	646	598	534	628	696	641	667	877
Yukon	11	8	10	10	10	10	10	11	11	11	11
N.W.T.	19	21	17	5	5	12	12	12	12	12	12
Canada	**8 537**	**7 913**	**7 798**	**7 528**	**7 103**	**7 782**	**8 150**	**8 681**	**8 887**	**8 955**	**8 925**

Table 12.10
Forecast of Capital Expenditures for Major Electric Utilities (Generation)

	1993*	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
	(millions of current dollars)										
Nfld.	11	17	18	17	41	79	31	31	31	31	31
P.E.I.	4	25	1	1	1	1	1	1	1	1	1
N.S.	63	26	24	27	28	29	29	30	30	31	32
N.B.	431	240	192	44	32	32	31	47	47	47	47
Que.	1 833	1 588	1 506	1 772	1 913	2 387	2 692	2 903	3 002	2 820	2 512
Ont.	1 546	1 062	962	726	513	495	461	488	394	396	442
Man	101	151	120	46	50	65	64	62	59	53	55
Sask.	84	80	110	42	51	23	28	35	13	29	14
Alta.	221	150	113	124	103	86	85	135	285	285	285
B.C.	33	84	107	120	127	178	267	299	179	276	161
Yukon	2	2	3	3	3	3	3	3	3	3	3
N.W.T.	11	16	12	10	10	10	10	10	10	10	10
Canada	**4 340**	**3 441**	**3 168**	**2 932**	**2 872**	**3 388**	**3 701**	**4 044**	**4 054**	**3 982**	**3 593**

*Actual data

Source: Canadian Electric Utilities and Natural Resources Canada

Table 12.11
Forecast of Capital Expenditures for Major Electric Utilities (Transmission)

	1993*	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
	(millions of current dollars)										
Nfld.	10	7	8	6	7	6	9	9	9	9	9
P.E.I.	0	1	1	1	1	0	0	0	0	0	0
N.S.	16	16	19	23	20	21	21	22	23	23	23
N.B.	53	11	10	13	10	10	11	11	11	11	11
Que.	835	817	609	489	273	365	381	429	594	863	692
Ont.	175	474	374	440	481	532	513	514	390	365	369
Man.	103	85	117	103	0	49	86	97	111	60	28
Sask.	11	30	52	16	14	25	20	11	3	5	4
Alta.	58	57	65	16	14	25	20	11	3	5	4
B.C.	68	122	95	144	131	115	100	79	95	85	125
Yukon	3	1	1	1	1	1	1	1	1	1	1
N.W.T.	1	1	1	1	1	1	1	1	1	1	0
Canada	**1 333**	**1 622**	**1 352**	**1 286**	**975**	**1 180**	**1 205**	**1 233**	**1 315**	**1 490**	**1 512**

Table 12.12
Forecast of Capital Expenditures for Major Electric Utilities (Distribution)

	1993*	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
	(millions of current dollars)										
Nfld.	30	25	31	33	30	30	31	31	31	31	31
P.E.I.	6	7	7	7	6	6	6	6	6	6	6
N.S.	42	40	45	45	47	47	48	49	50	51	52
N.B.	38	37	38	39	39	41	42	43	43	43	43
Que.	826	837	1 134	1 086	1 151	1 234	1 259	1 337	1 376	1 349	1 401
Ont.	419	193	187	188	196	203	211	220	229	219	247
Man.	60	63	64	61	57	55	59	58	59	61	64
Sask.	116	127	131	127	129	144	120	122	108	117	110
Alta.	140	123	122	112	104	107	109	110	113	111	111
B.C.	231	252	267	273	286	240	260	289	298	304	306
Yukon	5	4	5	5	5	5	6	6	6	6	6
N.W.T.	3	3	3	3	3	1	1	1	1	1	1
Canada	**1 916**	**1 711**	**2 023**	**1 979**	**2 053**	**2 113**	**2 152**	**2 272**	**2 320**	**2 299**	**2 378**

*Actual data

Source: Canadian Electric Utilities and Natural Resources Canada

Table 12.13
Forecast of Capital Expenditures for Major Electric Utilities (Other)

	1993*	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
	(millions of current dollars)										
Nfld.	8	15	19	16	9	9	12	12	12	12	12
P.E.I.	2	3	2	2	2	2	2	2	2	2	3
N.S.	11	18	13	10	9	8	8	8	8	8	9
N.B.	8	7	10	10	10	10	11	11	11	11	11
Que.	546	623	764	814	812	754	745	734	746	801	846
Ont.	148	288	271	272	212	207	205	214	214	238	168
Man.	36	31	41	44	44	46	47	61	74	48	47
Sask.	18	23	18	16	20	21	18	18	19	19	19
Alta.	68	50	55	46	39	42	42	42	42	42	42
B.C.	108	79	49	109	54	1	1	29	69	2	285
Yukon	1	1	1	1	1	1	1	1	1	1	1
N.W.T.	5	2	2	2	2	0	0	0	0	0	0
Canada	**949**	**1 140**	**1 245**	**1 342**	**1 214**	**1 101**	**1 092**	**1 132**	**1 198**	**1 184**	**1 442**

*Actual data

Source: Canadian Electric Utilities and Natural Resources Canada

Table 12.14
Forecasts of SO_2 Emissions by Fuel Type in Canada (1 000 tonnes)

Year	Coal	Oil
1993	483	110
1994	426	84
1995	392	92
2000	413	104
2005	412	139
2010	434	180

Source: Canadian Electric Utilities

Table 12.15
Forecasts of NO_x Emissions by Fuel Type in Canada (1 000 tonnes)

Year	Coal	Oil	Natural Gas
1993	173	28	7
1994	170	20	6
1995	162	25	6
2000	183	27	9
2005	191	38	16
2010	201	37	17

Source: Canadian Electric Utilities

Figure 12.1 Comparison of Electrical Energy Demand Forecasts in Canada

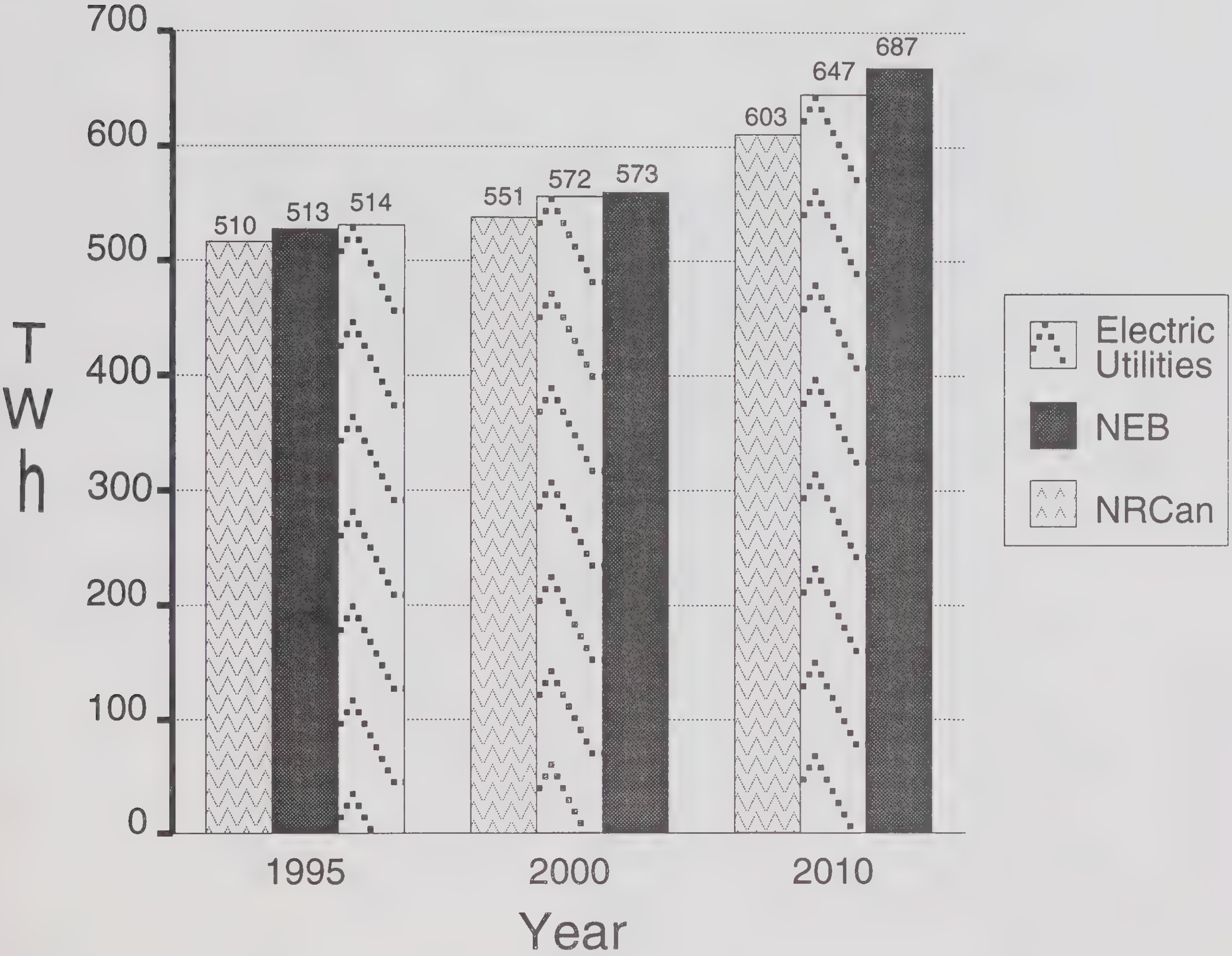


Figure 12.2 Comparison of Installed Generating Capacity Forecasts in Canada

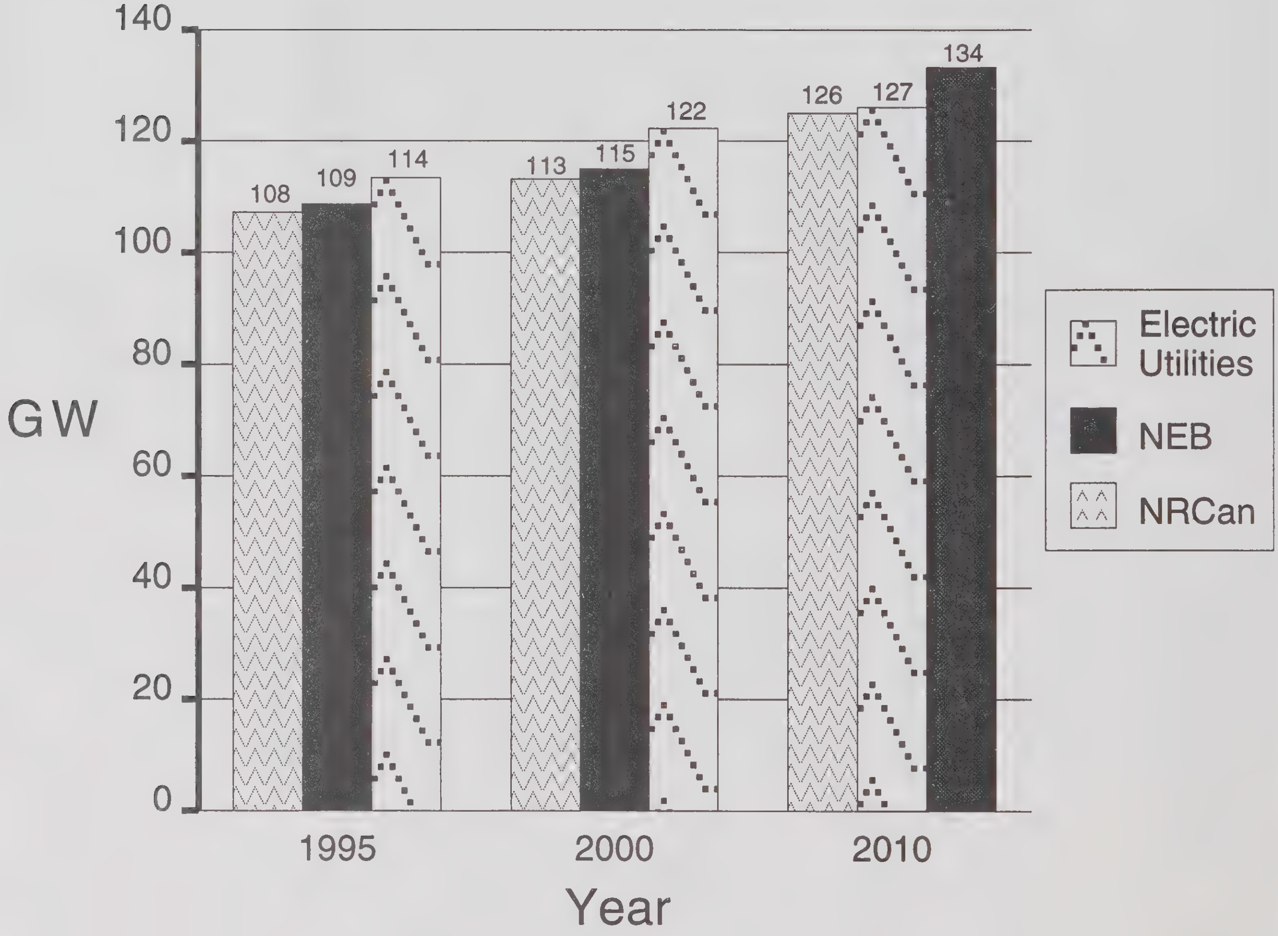


Figure 12.3 Comparison of Electricity Generation Forecasts in Canada

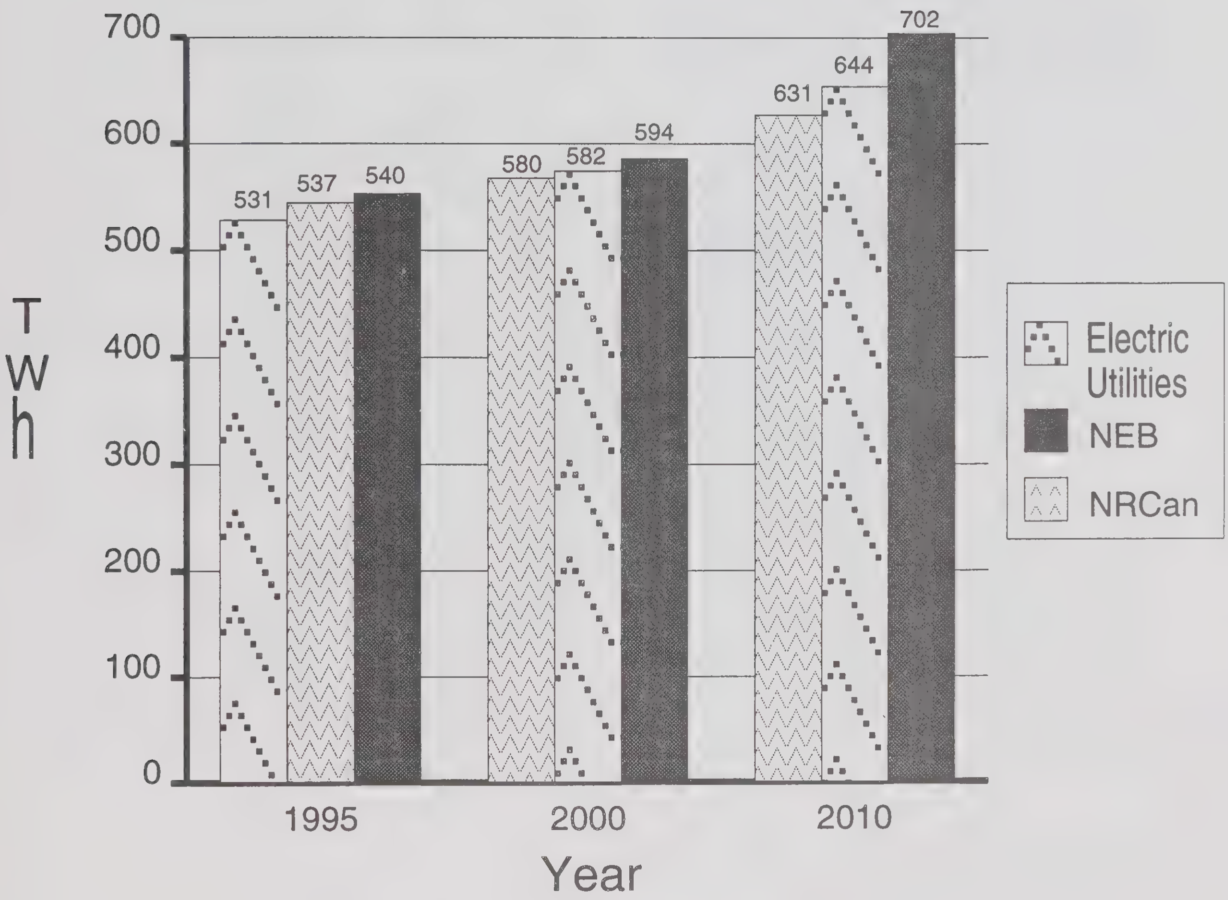
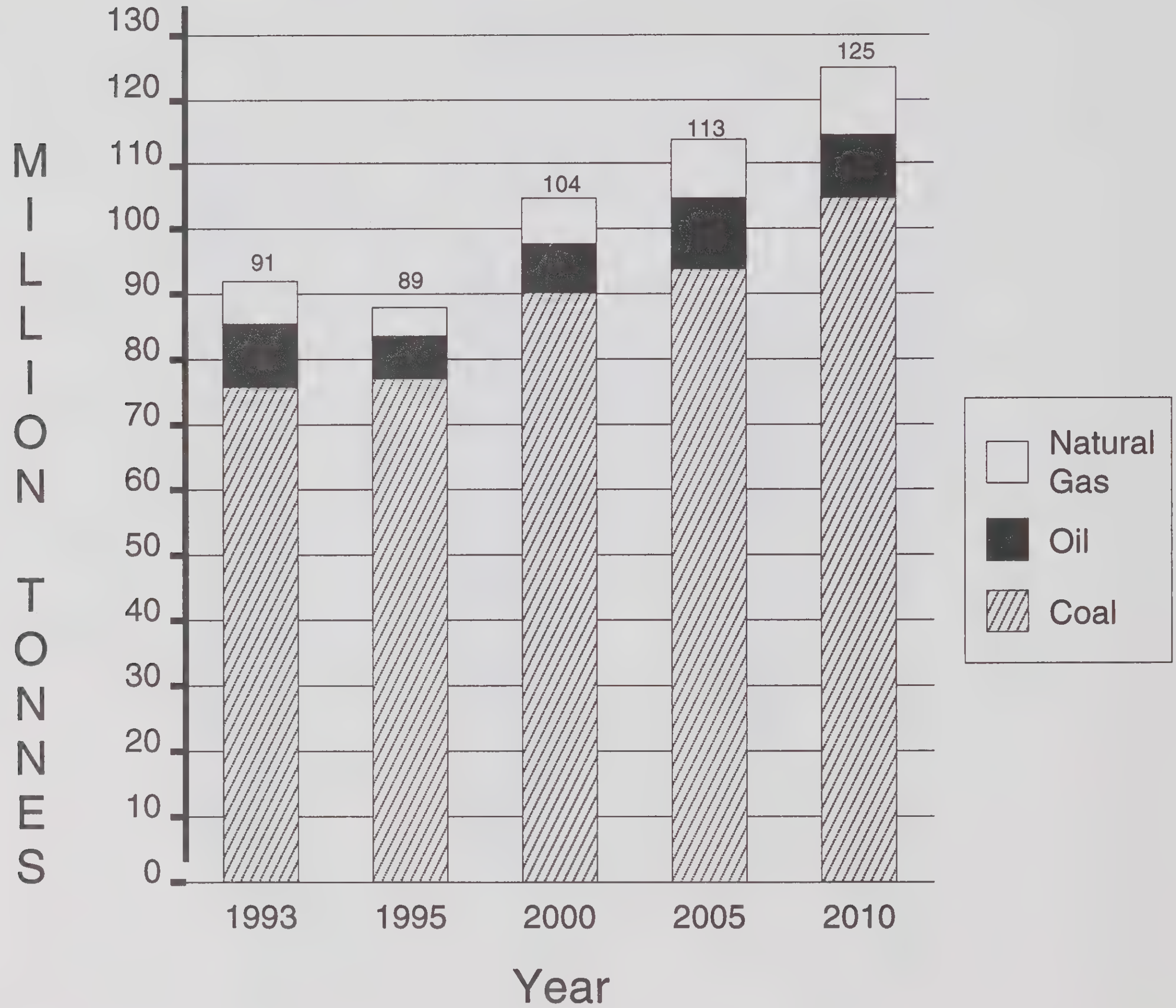


Figure 12.4 Forecasts of CO_2 Emissions by Fuel Type in Canada



Chapter 13

Demand-Side Management

Importance of Demand-Side Management

Demand-Side Management (DSM) is defined as the planning and implementation of electric utility activities that influence customer use of electricity in ways that will promote desirable changes in the utility's load shape.

Managing electrical demand is not a new concept for Canadian electric utilities. Utilities have been offering lower rates for interruptible service for many decades, and utility research into improving the efficiency of lighting dates back to the beginning of the century. Since entering the 1990s, however, the utilities have been increasing their efforts in demand-side management, and in some provinces individual initiatives are being integrated into comprehensive demand-management programs. Some of the programs include, Hydro-Québec's Energy Efficiency Project; Ontario Hydro's fuel substitution and efficiency standards; TransAlta Utilities' demand-oriented rates; and B.C. Hydro and SaskPower's *Power Smart*, which is designed to create an awareness of energy conservation. Canadian utilities see these programs as a means of providing quality electrical service in a flexible, economic and environmentally sensitive manner.

The traditional role of the electric utility has been to respond to increases in the demand for electrical energy by building new generating capacity. This approach has led to surplus capacity and a waste of resources when the increased demand did not materialize.

Operations designed to meet rather than manage load have cost implications for the utility and eventually the utility's customers. Under traditional utility planning practices, an increase in load results in a need to bring additional generating resources on-line. Over time, utilities are forced to develop more expensive generating resources, e.g. isolated hydroelectric projects, new or different fuel sources, and imports. New developments become increasingly more expensive and in some cases, are also associated with large environmental costs.

To serve this load growth, utilities have had to adapt their operations to customer-use patterns. To do this while keeping generation costs low, utilities have had to optimize the use of their supply. Two considerations are important in this optimization: (i) the fixed and variable costs of various forms of production, and (ii) the costs of changing electrical output levels over a short period of time. As a result of these cost considerations, the most economic means of serving load, generally, has been for utilities to maximize the use of generation with (i) low variable cost sources (hydro and nuclear facilities) to serve baseload requirements and (ii) higher variable cost sources (coal, gas and pumped storage) to serve intermediate- and peak-load requirements. Figure 13.1 illustrates the resources that a typical utility might use to meet its annual load.

As Canadian utilities evaluate the means of providing electrical service to meet future demand, increasingly they are faced with a difficult choice between rising costs of generation and the cost of DSM options.

Objectives of DSM

Utilities generally pursue DSM in order to (i) maximize efficiency in their existing operations (i.e. reduce the use of costlier

fuels and the period that generating plants sit idle); and (ii) minimize the requirement for new plants (i.e. reduce the need for peaking capacity, and delay the need for baseload capacity additions). The achievement of these goals brings a number of economic and environmental benefits, particularly low electricity rates and reduced environmental impacts.

There are five key objectives of DSM. They are:

Load Reduction -- reducing the amount of electricity required by customers. This can be achieved by improving electrical end-use efficiency.

Load Shifting -- reducing peak electricity demand by moving it to periods of lighter demand. An example of this type of initiative is time-of-use rates that reflect the higher cost of providing electricity during periods of peak demand.

Peak Clipping -- reducing peak electricity demand without shifting it to another period. This can be achieved by offering preferential rates to consumers willing to have load interrupted during peak periods.

Valley Filling -- promoting electricity use during off-peak hours to increase baseload generation and the efficiencies related to it. This can be achieved through reduced rates.

Load Building -- promoting electricity consumption during both the peak and the off-peak periods. Load building can be done through incentives to attract large electricity consumers.

These classifications and examples of typical programs designed to achieve DSM objectives are illustrated in Figure 13.2.

A utility decides which aspects of DSM it will implement based on its balance of demand and supply. Utilities that find themselves with significant excess supply because of a major loss of load, a recent large capacity addition, or lower than anticipated load growth, will tend to emphasize load-building programs. Conversely, as utilities approach a load/resource balance, they will likely emphasize load reduction or shifting efforts.

During the early and mid-1980s, many Canadian utilities had surplus generating capacity resulting from lower than anticipated demand. At that time, some utilities introduced programs to build load. These initiatives included advertising campaigns to increase consumption, preferential rates designed to attract energy-intensive industries, programs to promote fuel switching to electricity, and increased electricity export marketing efforts.

Today, the focus has changed. As average Canadian net surplus capacity has declined from 14 per cent in 1980 to 8 per cent in 1993 (see Table 7.7), utilities have cut programs to build load and begun to aggressively pursue load-reduction and load-shifting initiatives individually or in the context of a comprehensive DSM program. Generally these programs involve one or more alternative pricing policies, direct incentives, direct customer contact, and advertising.

DSM Initiatives

For ease of description, the types of initiatives utilities have embarked upon can be grouped into three classifications: energy efficiency improvements, load shifting, and interruptible load. Energy efficiency improvements are the main focus of electric utility DSM initiatives and programs.

Energy efficiency improvements include utility initiatives designed to increase the efficiency of electricity use among the utility's customers and thereby reduce load. These types of initiatives are generally intended to either improve the penetration of energy-efficient equipment in the marketplace or improve customers' operation of electrical equipment.

Load shifting refers to efforts by the utility to alter the timing of electrical demand among its customers. The goal of load shifting is to reduce peak demand that occurs in the daylight hours and, in Canada, during the winter. Demand is shifted to non-peak periods but total energy demand is not reduced.

Load shifting is more popular among utilities (i) where capacity is constrained, i.e., thermal as opposed to hydraulic systems, and (ii) where meeting the peak requires the operation of more expensive generating units or units with greater environmental impacts. Load shifting is generally done through rate design or direct control.

Interruptible load is the third type of DSM load reduction. It is also possibly the DSM initiative with which utilities have had the most experience. Interruptible load contracts are generally offered to large electricity consumers that have some form of back-up generation. Usually these are industrial or large institutional customers. In an interruptible load contract, the customer receives a preferential electricity rate in return for accepting the risk that electrical service will be curtailed intentionally by the utility in periods of high demand and tight supply.

Utility/Federal Cooperation

As outlined above, utilities implement a variety of programs in order to achieve their DSM objectives. Some of these programs are carried out in cooperation with Natural Resources Canada's (NRCan) Efficiency and Alternative Energy Branch. NRCan's *Partners in Integrated Resources Planning (PIRP)* Initiative deals with electrical and natural gas DSM, non-utility generation, co-generation and district heating and cooling.

PIRP will bring together various stake-holders in order to increase the adoption of DSM, non-utility generation, and other energy management techniques within the energy sector. It will act to coordinate and catalyze integrated planning and program efforts. Joint activities will involve energy supply stakeholder and manufacturers and suppliers of energy efficient and energy management equipment.

Utilities in the Maritime provinces, for example, contribute to NRCan's *Federal Buildings Initiatives (FBI)*, which is aimed at introducing energy efficiency programs for federal facilities. Another example of utility partnership with NRCan is in Saskatchewan, where SaskPower and NRCan are investigating opportunities to implement energy efficiency at Regina Airport.

A number of utilities have also entered into agreements with NRCan to cooperate on ventures related to NRCan's *R-2000 Efficient Home Program, Energy Innovators,* and industrial energy programs.

DSM and Canadian Electric Utilities

Prior to 1993, Canadian electric utilities saved 5055 MW of generating capacity resulting from the implementation of DSM programs, which accounted for 4.5 per cent of the total installed generating capacity. Hydro-Québec had the highest savings of 3300 MW, followed by Ontario Hydro with 883 MW and B. C. Hydro with 304 MW.

Table 13.1 summarizes Canadian utilities' forecasts of generating-capacity savings resulting from the implementation of DSM initiatives and programs for the years 1994, 2000 and 2010. The capacity savings are cumulative.

By the end of 1994, Canadian electrical utilities forecast DSM generating-capacity savings of about 5604 MW. The majority of the projected DSM savings will result from capacity interruptible load initiatives. This reflects mainly historic contracts with large consumers that are willing to accept occasional interruptions in service in exchange for reduced electrical rates. Most utilities offer such interruptible contracts. Hydro-Québec predicts 1670 MW of capacity interruptible load in 1994.

Load shifting will also contribute significantly to generating capacity savings, particularly as a result of Hydro-Québec's dual-energy program. Under this program, residential, commercial and industrial consumers use electricity for heating most of the time, but switch to another source of energy, such as heating oil, during peak heating periods (defined as when the temperature drops below a certain bench-mark). In exchange for switching off electricity during these peak periods, customers on this program receive a reduced rate for their off-peak consumption. Hydro-Québec projects a savings of 1340 MW in load shifting in 1994.

Only 15 per cent of 1992 Canadian utility capacity savings from DSM came from energy-efficiency improvements. However, this percentage is expected to increase to 31 per cent in 1994, reflecting the time lag of program development, implementation and penetration.

By the year 2000, the total DSM savings are expected to climb to 9314 MW. At that time, about 52 per cent of the DSM savings will result from energy-efficiency improvements. These initiatives will be the basis of DSM programs for B.C. Hydro, Manitoba Hydro, Ontario Hydro, Hydro-Québec and New Brunswick Power. Utilities in Newfoundland, the Maritimes, Nova Scotia and Alberta will continue to rely on capacity interruptible load for the bulk of their DSM savings. Electrical efficiency improvements will continue to be the major source of generating capacity savings to the year 2010. By that time, total savings are expected to climb to 11 411 MW. Of this total, 7207 MW (or 63 per cent) is attributed to electrical efficiency improvements.

Figure 13.3 illustrates the sectors from which the forecast savings will come. The information shows that in 1994, 63 per cent of the savings will come from the commercial and residential sectors, reflecting the emphasis utilities have placed on energy efficiency improvements with these customers. By the year 2000, the distribution of savings will be more or less the same as in 1994. This reflects the anticipated success of energy-efficiency improvements in the commercial and residential sectors, particularly improvements in lighting efficiency. Industrial savings are expected to account for only 17 per cent of total peak-load savings by the year 2000.

Table 13.2 summarizes energy savings resulting from electrical efficiency improvements. It is estimated that about 8373 GWh of electricity will be saved in 1994, compared with 4151 GWh in 1992, and 6110 GWh in 1993. The real impact of initiatives in this area will be significant by the year 2000, approaching 24 717 GWh. The energy-savings are expected to increase to about 39 000 GWh by 2010.

Projected Capital Costs of DSM

Most utilities are unable to estimate the costs of the DSM programs and initiatives that they are planning to undertake. Part of the reason relates to difficulties in determining the penetration rate of such programs. Another reason is that load reduction programs account for much of the DSM effort, and establishing the costs of these programs is complex and in many instances dependent upon the frequency of unanticipated shortages. Some of the smaller utilities identified that their DSM planning is not as detailed nor as long-term as other resource planning.

In 1993, all electric utilities in Canada with the exceptions of Newfoundland and Nova Scotia had invested a total of $331 million in DSM programs. Ontario Hydro was the largest spender with $130 million, followed by Hydro-Québec with $117 million and B.C. Hydro with $66 million. Only a few utilities have projected DSM expenditures to the year 2000: Hydro-Québec is intending to spend $243 million, followed by B.C. Hydro with $53 million and Manitoba Hydro with $41 million.

Tables and figures referred to in this chapter are on the following pages.

Tables & Figures

Table 13.1
Generating Capacity Savings from Electric Utilities' DSM Cumulative Values

	1993	1994				2000				2010			
	Actual	EEI*	LS*	CIL*	Total	EEI	LS	CIL	Total	EEI	LS	CIL	Total
						(MW)							
Nfld.	0	0	0	46	46	0	0	46	46	0	0	46	46
P.E.I.	24	3	0	24	27	3	0	25	28	3	0	25	28
N.S.	158	0	0	166	166	68	0	187	255	239	0	236	475
N.B.	93	25	0	80	105	141	0	80	221	266	0	80	346
Que.	3 300	400	1 340	1 670	3 410	2 030	1 540	1 780	5 350	3 760	1 270	1 780	6 810
Ont.	883	885	228	0	1 113	1 638	422	0	2 060	1 638	422	0	2 060
Man.	54	23	0	42	65	143	0	79	222	224	0	85	309
Sask.	0	0	0	0	0	16	0	0	16	119	0	0	119
Alta.	238	9	0	246	255	16	0	260	276	16	0	260	276
B.C.	304	416	0	0	416	839	0	0	839	941	0	0	941
Yukon	1	1	0	0	1	1	0	0	1	1	0	0	1
N.W.T.	0	0	0	0	0	0	0	0	0	0	0	0	0
Canada	**5 055**	**1 762**	**1 568**	**2 274**	**5 604**	**4 895**	**1 962**	**2 457**	**9 314**	**7 207**	**1 692**	**2 512**	**11 411**

* Note: EEI - Electrical Efficiency Improvements
LS - Load Shifting
CIL - Capacity Interruptible Load

Source: Obtained from a survey undertaken by the Electricity Branch, Natural Resources Canada, January 1994

Table 13.2
Energy Savings from Electrical Utilities' Efficiency Improvement Programs

	1993 Actual	1994	2000	2010
		(GWh)		
Nfld.	0	0	0	0
P.E.I.	7	10	10	10
N.S.	0	0	246	815
N.B.	46	115	584	1 190
Quebec	1 150	1 940	10 240	20 020
Ontario	3 204	4 104	8 745	8 745
Manitoba	89	111	631	967
Sask.	0	0	51	488
Alberta	104	32	56	56
B.C.	1 505	2 061	4 154	4 655
Yukon	5	0	0	0
N.W.T.	0	0	0	0
Canada	**6 110**	**8 373**	**24 717**	**36 946**

Source: Obtained from a survey undertaken by the Electricity Branch, Natural Resources Canada, January 1994.

Figure 13.1 **Typical Annual Load Duration Curve and Generation Cost Minimization for an Electric Utility**

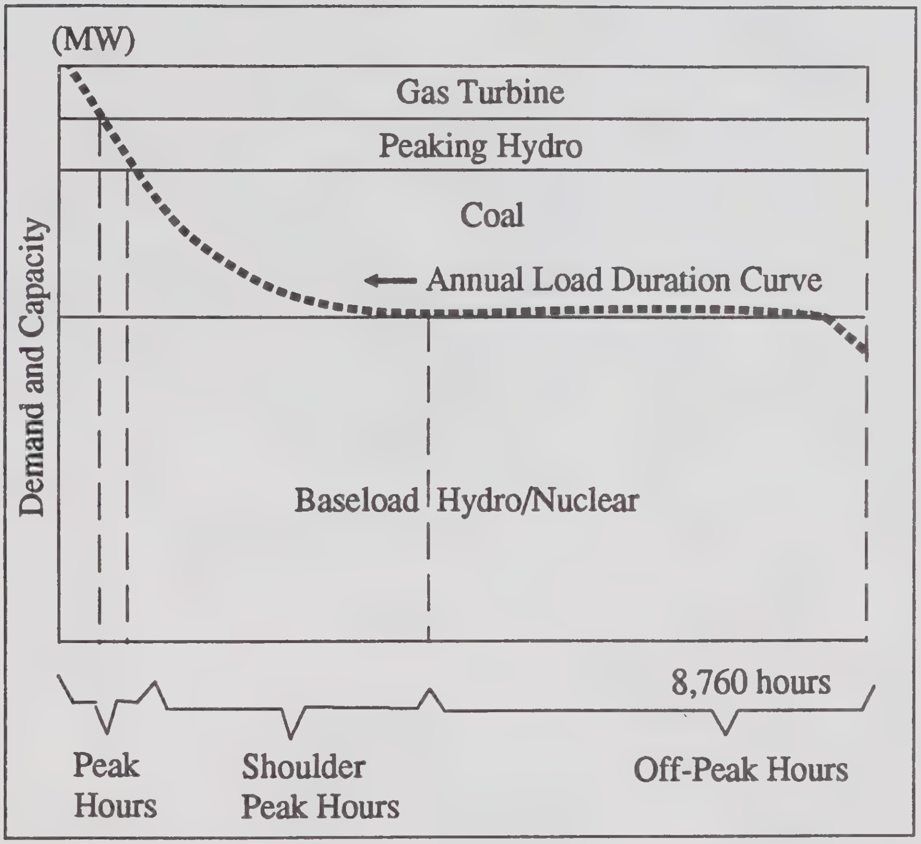
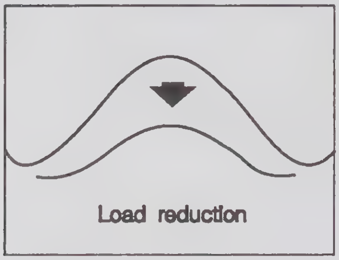
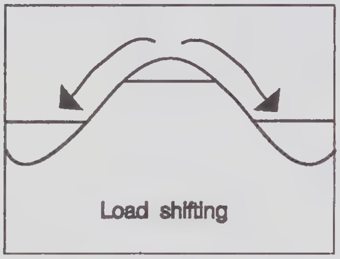


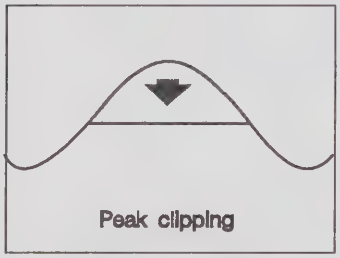
Figure 13.2 Demand-side Management Objectives and Programs



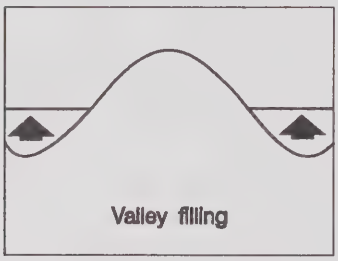
- improvements to end-use efficiency
- rate increases and restructuring



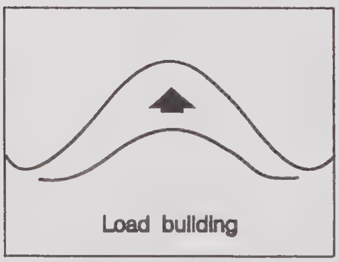
- time-of-use rates
- off-peak rates
- thermal energy storage
- direct load control



- time-of-use rates
- interruptible rates
- direct load control

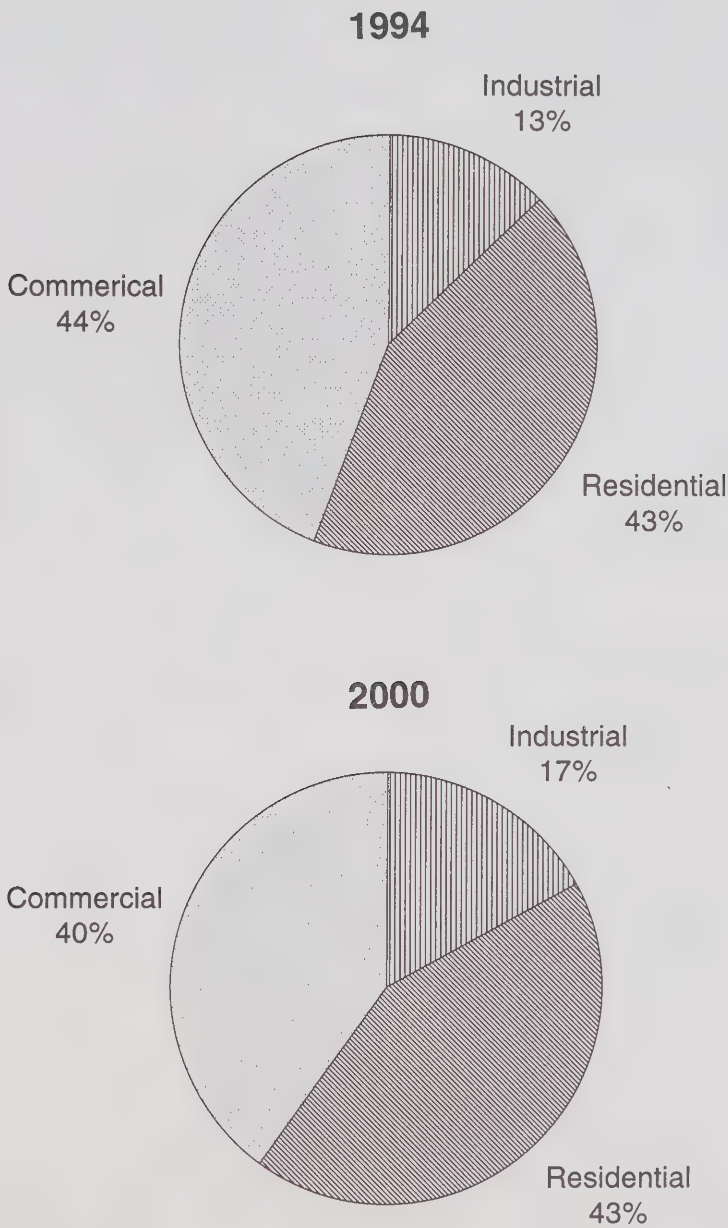


- time-of-use rates
- seasonal rates
- off-peak rates
- thermal energy storage



- promotional rates
- industrial electrotechnologies
- dual-fuel heating
- export marketing

Figure 13.3 Generating Capacity Savings by Sector due to DSM*



* Based on utility responses identifying capacity savings by sector, i.e., total savings in 1994 of 3420 MW and in 2000 of 6020 MW.

Non-Utility Generation

Traditional suppliers of electricity in Canada include investor-owned, provincial, municipal and territorial electric utilities. Minor utilities and large industry have also contributed to the supply of electricity. Over the past several years, however, environmental concerns, rising electricity rates, and growing international competition have led to a re-examination of alternative sources of electricity such as independent power producers (IPPs).

Non-utility generation (NUG) is defined here as electricity generation from facilities owned and operated by companies other than the major electric utilities reported in Table 1.1. In this chapter, non-utility generation consists of industrial establishments, minor utilities, and independent power production. This chapter examines the current contribution to electricity capacity and generation from NUG, the power purchase policies of the major utilities, and the future potential for NUG in Canada.

Current NUG Status

As of December 31, 1993, the total installed NUG capacity in service in Canada was estimated to be 8934 MW, or about 8 per cent of Canada's total generating capacity. Of this total, 6399 MW (72 per cent) was owned and operated by industrial establishments, mainly pulp and paper, mining, and aluminum smelting companies (Table 14.1). The remaining 2535 MW was owned by minor utilities (Table 14.2) and independent power producers (Table 14.3).

The largest share of installed NUG capacity is hydro, about 6044 MW or 68 per cent of the total. Natural gas contributed 1653 MW or 18 per cent of total NUG generation; waste fuels, including wood waste, flare gas, etc., contributed 968 MW or 11 per cent; and oil contributed 269 MW or 3 per cent. NUG fuelled by natural gas, oil, wood waste, and flare gas was in the form of co-generation (i.e. generation producing electricity, and useable heat generally in the form of steam). This form of NUG capacity totalled 2665 MW in 1993. Of this total, about 38 per cent is located in Ontario, 27 per cent in Alberta, 18 per cent in British Columbia, and 7 per cent in Quebec.

It is estimated that a total of 53 762 GWh of electricity was generated by NUG facilities in 1993, accounting for 10.5 per cent of total Canadian electricity generation. Of this total, 39 808 GWh (74 per cent) was self-generation by large industry, and the remainder was generated by minor utility and independent power generators. (Tables 14.5 and 14.6). Of the total 53 762 GWh of non-utility generation, about 38 589 GWh (72 per cent) was hydroelectric, followed by natural gas with 9932 GWh (18 per cent), other generation with 4368 GWh (8 per cent) and oil with 873 GWh (2 per cent).

Power Purchase Policies

Electricity supplied by a non-utility generator may be sold to a major electric utility or used to meet the producer's own electricity needs, i.e. self-generation. Although non-utility generators produced 53 762 GWh of electricity in 1993, it is estimated that only 6253 GWh (12 per cent) of this was sold to the major utilities. Ontario Hydro purchased about 4414 GWh, followed by B.C. Hydro (934 GWh) and Hydro-Québec (313 GWh).

All major electric utilities have established policies concerning the purchase of electricity from NUG projects. Most utilities purchase electricity from non-utility generators at rates that reflect their long-term value to the power system. Appendix C summarizes power

purchase rates of the major utilities across Canada for non-utility generation.

The following briefly outlines some NUG policies and developments in selected provinces.

Ontario Hydro has established the following policy elements for NUG: to remain committed to NUG as an essential part of future energy supply; to purchase electricity from non-utility generators at rates that reflect the costs Ontario Hydro would incur to generate the power; to purchase electricity from non-utility generators with power ratings of 5 MW or less through standard pre-approved rate schedules; and to purchase electricity from non-utility generators with power ratings greater than 5 MW through negotiation or by requests for proposals.

In Alberta, the provincial government passed the *Small Power Research and Development Act* (the Act) on May 11, 1988. The purpose of the Act is to facilitate the generation of electricity in Alberta through small projects using wind, hydro, and biomass resources, and to monitor production from small power projects. The results of the monitoring will allow Alberta to determine the contribution that small power projects can make to the province's electricity supply in the long term.

Under the Act, the purchase price for NUG projects is fixed at 5.2 cents per kWh until 1994, and the amount of power purchased at this price will be limited to 125 MW. The purchase contracts will be limited to between 15 and 25 years.

On October 15, 1992, the government of British Columbia announced its policy on the role of independent power producers in meeting domestic electricity needs. Acquisition of electricity from IPPs will be driven by domestic needs, and resources will be acquired according to their social costs. IPPs will not be invited to bid on hydro sites in basins already developed by B.C. Hydro, or on large hydro sites (in excess of 100 MW) in undeveloped basins that B.C. Hydro could efficiently develop. With respect to small power opportunities (under 5 MW), B.C. Hydro and the provincial government will identify areas where independent power developments would be appropriate and issue specific requests for proposals.

In British Columbia, all electricity generating resources acquisition will be evaluated on a social cost basis, and the final prices determined through competitive process. Social costs and benefits will be incorporated through an evaluation framework that includes recognition of the potential of NUG projects to reduce environmental problems and provide employment opportunities in areas of high regional unemployment. In addition, POWEREX will assist the development of IPPs for export by providing technical and market expertise to the private sector. POWEREX will also facilitate arrangements for IPPs to deliver power to the export market.

Although Hydro-Québec has purchased electricity produced by industry for some time, Hydromega Development was the first independent power producer in Quebec to develop and operate small hydro generating stations expressly for the purpose of selling the output to Hydro-Québec. Hydromega owns and operates two hydro generating stations with installed capacities of 2.4 MW and 2.0 MW. Hydro-Québec purchases Hydromega's output at rates based on marginal costs. The term of the contract is 20 years.

In Saskatchewan, there are no NUG projects operating under contract to SaskPower. The province has 43 MW of installed cogeneration capacity ranging from 26 MW at the Weyerhaeuser pulp mill near Prince Albert, to a small unit at the North Battleford Hospital. These are self-generation projects which do not produce electricity for sale to SaskPower. However,

SaskPower has indicated that proposals are being requested for 25 MW of NUG capacity for start-up in 1995. This request will allow SaskPower to gain experience with NUG. As indicated in Appendix C, the power purchase rates of the major utilities are generally based on avoided-cost principles. As a result, the price of purchases of non-utility generation should generally be equal to or less than the cost of future generation by the major utilities.

NUG Potential in Canada

This section presents the forecasts of the major electric utilities for non-utility generation expected to come into service over the planning period 1994-2010. The utilities have prepared the forecasts based in part on the economics of non-utility generation from the perspective of the NUG developer, and have taken into account the developers' equipment costs, fuel costs, and return on investment, as well as the projected purchase rates offered by the utilities.

Among the non-utility generators, IPPs are of great importance and interest to major utilities. The projections of NUG potential therefore concentrate mainly on IPPs. Table 14.7 summarizes the projections of IPPs' generating capacity for the period 1994-2010. According to major utilities' estimates, a total of 2674 MW of IPP capacity is attainable by the year 2000. Of this total, co-generation, fuelled mainly by natural gas, will account for 44 per cent, followed by other thermal (waste fuels) with 39 per cent and small hydro with 17 per cent.

By 2000, it is projected that the majority of new independent power producers will be located in Ontario (60 per cent), British Columbia (16 per cent), and Quebec (14 per cent). By 2010, it is estimated that total attainable IPP capacity will increase to 2694 MW. Co-generation fuelled by natural gas will continue to supply the largest share of total IPPs in 2010 with 44 per cent, followed by other thermal with 40 per cent, and small hydro with 16 per cent. It is also forecast that Ontario will continue to have the largest share of IPPs with 59 per cent of total independent power production in 2010. The growth in IPPs reported above is substantially less than that forecasted by major utilities last year in which independent power production was expected to reach 3836 MW by the year 2010. The reduction stems primarily from reduced projections of growth in electricity demand and the consequent reduction in the need for new generating capacity.

The future development of NUG will depend on the profitability of NUG projects and the need for additional generating capacity. Achieving an acceptable rate of return on investment is a critical factor for non-utility generators. According to Ontario Hydro's estimates, rates of return on investment in the range of 15 to 20 per cent are required by a developer before a NUG project will be undertaken. The rate of return is linked to the purchase rate offered by the major utilities. With regard to the need for additional capacity, most of the major utilities will not require additional generating capacity for some years and thus may defer purchases from non-utility generators in the near term.

At present, the amount of electricity generated in Canada from non-utility generators is relatively small. However, in the past few years, electricity planners have begun to give NUG a much greater emphasis, especially where such generation is produced from renewable or waste resources, or at higher efficiencies than conventional generators. It is expected that NUG will play an increasingly important role in the development of Canada's electricity service in the next decade or two.

Tables are on the following pages.

Tables & Figures

Table 14.1
Industrial Installed Generating Capacity by Fuel Type, 1993

	Conventional Thermal							
	Coal	Oil	Gas	Sub-Total	Nuclear	Hydro	Other	Total
				(MW)				
Nfld.	0	11	0	11	0	78	0	89
P.E.I.	0	0	0	0	0	0	0	0
N.S.	0	29	0	29	0	5	19	53
N.B.	0	70	0	70	0	17	87	174
Quebec	0	22	8	30	0	2 782	5	2 817
Ontario	0	0	429	429	0	248	117	794
Manitoba	0	0	4	4	0	0	23	27
Sask.	0	22	36	58	0	0	22	80
Alberta	0	1	318	319	0	0	99	418
B.C.	0	95	51	146	0	1 305	471	1 922
Yukon	0	0	0	0	0	0	0	0
N.W.T.	0	3	19	22	0	3	0	25
Canada	**0**	**254**	**865**	**1 119**	**0**	**4 438**	**842**	**6 399**

Source: Electric Power Statistics, Volume III, Statistics Canada, catalogue 57-206 and Electricity Branch, Natural Resources Canada

Table 14.2
Minor Utility Installed Generating Capacity by Fuel Type, 1993

	Conventional Thermal							
	Coal	Oil	Gas	Sub-Total	Nuclear	Hydro	Other	Total
				(MW)				
Nfld.	0	0	0	0	0	134	0	134
P.E.I.	0	0	0	0	0	0	0	0
N.S.	0	0	0	0	0	0	0	0
N.B.	0	1	0	1	0	34	0	35
Quebec	0	0	0	0	0	638	0	638
Ontario	0	12	0	12	0	438	0	450
Manitoba	0	0	0	0	0	0	0	0
Sask.	0	0	0	0	0	0	0	0
Alberta	0	0	0	0	0	0	0	0
B.C.	0	0	0	0	0	211	0	211
Yukon	0	0	0	0	0	0	0	0
N.W.T.	0	0	0	0	0	0	0	0
Canada	**0**	**13**	**0**	**13**	**0**	**1 455**	**0**	**1 468**

Source: Electric Power Branch, National Energy Board, March 1994 and Electricity Branch, Natural Resources Canada, March 1994

Table 14.3
Independent Power Producer Installed Generating Capacity by Fuel Type, 1993

	Conventional Thermal							
	Coal	Oil	Gas	Sub-Total	Nuclear	Hydro	Other	Total
				(GWh)				
Nfld.	0	0	0	0	0	0	0	0
P.E.I.	0	0	0	0	0	0	0	0
N.S.	0	0	0	0	0	0	0	0
N.B.	0	2	0	2	0	9	0	11
Quebec	0	0	30	30	0	29	8	67
Ontario	0	0	593	593	0	82	42	717
Manitoba	0	0	0	0	0	0	0	0
Sask.	0	0	60	60	0	0	0	60
Alberta	0	0	0	0	0	23	21	44
B.C.	0	0	105	105	0	8	55	168
Yukon	0	0	0	0	0	0	0	0
N.W.T.	0	0	0	0	0	0	0	0
Canada	**0**	**2**	**788**	**790**	**0**	**151**	**126**	**1 067**

Source: Electric Power Branch, National Energy Board, March 1994 and Electricity Branch, Natural Resources Canada, March 1994

Table 14.4
Industrial Energy Generation by Fuel Type, 1993

	Conventional Thermal							
	Coal	Oil	Gas	Sub-Total	Nuclear	Hydro	Other	Total
				(GWh)				
Nfld.	0	1	0	1	0	520	0	521
P.E.I.	0	0	0	0	0	0	0	0
N.S.	0	174	0	174	0	34	153	361
N.B.	0	362	0	362	0	68	242	672
Quebec	0	0	0	0	0	19 725	0	19 725
Ontario	0	0	1 847	1 847	0	1 483	203	2 533
Manitoba	0	6	20	26	0	0	41	67
Sask.	0	36	198	234	0	0	170	404
Alberta	0	0	2 332	2 332	0	0	1 286	3 618
B.C.	0	560	245	805	0	10 919	1 247	12 971
Yukon	0	0	0	0	0	0	0	0
N.W.T.	0	0	95	95	0	25	0	120
Canada	**0**	**836**	**5 125**	**5 961**	**0**	**30 210**	**3 637**	**39 808**

Source: Electric Power Statistics, Volume III, Statistics Canada, catalogue 57-206 and Electricity Branch, Natural Resources Canada

Table 14.5
Minor Utility Energy Generation Capacity by Fuel Type, 1993

	Conventional Thermal							
	Coal	Oil	Gas	Sub-Total	Nuclear	Hydro	Other	Total
				(GWh)				
Nfld.	0	0	0	0	0	880	0	880
P.E.I.	0	0	0	0	0	0	0	0
N.S.	0	0	0	0	0	0	0	0
N.B.	0	0	0	0	0	137	0	137
Quebec	0	0	0	0	0	3 727	0	3 727
Ontario	0	1	0	1	0	1 829	0	1 830
Manitoba	0	0	0	0	0	0	0	0
Sask.	0	0	0	0	0	0	0	0
Alberta	0	0	0	0	0	0	0	0
B.C.	0	0	0	0	0	1 127	0	1 127
Yukon	0	0	0	0	0	0	0	0
N.W.T.	0	0	0	0	0	0	0	0
Canada	**0**	**1**	**0**	**1**	**0**	**7 700**	**0**	**7 701**

Source: Electric Power Branch, National Energy Board, March 1994, and Electricity Branch, Natural Resources Canada, March 1994

Table 14.6
Independent Power Producer Energy Generation Capacity by Fuel Type, 1993

	Conventional Thermal							
	Coal	Oil	Gas	Sub-Total	Nuclear	Hydro	Other	Total
				(GWh)				
Nfld.	0	0	0	0	0	0	0	0
P.E.I.	0	0	0	0	0	0	0	0
N.S.	0	0	0	0	0	2	0	2
N.B.	0	36	0	36	0	19	0	55
Quebec	0	0	203	203	0	107	3	313
Ontario	0	0	3 648	3 648	0	389	377	4 414
Manitoba	0	0	0	0	0	0	0	0
Sask.	0	0	420	420	0	0	0	420
Alberta	0	0	0	0	0	98	17	115
B.C.	0	0	536	536	0	64	334	934
Yukon	0	0	0	0	0	0	0	0
N.W.T.	0	0	0	0	0	0	0	0
Canada	**0**	**36**	**4 807**	**4 843**	**0**	**679**	**731**	**6 253**

Source: Electric Power Branch, National Energy Board, March 1994, and Electricity Branch, Natural Resources Canada, March 1994

Table 14.7
Projections of Attainable Independent Power Producer Generating Capacity

	1994	2000			2010		
		Hydraulic	Cogeneration	Other Thermal	Hydraulic	Cogeneration	Other Thermal
	(MW)						
Nfld.	0	38	0	0	38	0	0
N.S.	8	5	22	8	5	22	8
N.B.	11	4	0	52	4	0	52
Quebec	313	140	230	0	140	200	0
Ontario	894	149	834	614	149	834	614
Sask.	60	0	100	0	0	135	15
Alberta	91	52	0	0	52	0	0
B.C.	176	46	0	380	46	0	380
Canada	**1 553**	**434**	**1 186**	**1 054**	**434**	**1 191**	**1 069**

Source: Canadian electric utilities, March 1994

Table 14.8
Projections of Attainable Independent Power Producer Generation

	1994	2000			2010		
		Hydraulic	Cogeneration	Other Thermal	Hydraulic	Cogeneration	Other Thermal
	(GWh)						
Nfld.	0	218	0	0	218	0	0
N.S.	52	26	171	65	26	168	33
N.B.	74	25	0	372	25	0	372
Quebec	714	973	1 828	0	976	1 602	0
Ontario	5 611	655	5 802	4 589	655	5 802	4 589
Sask.	420	0	700	0	0	950	100
Alberta	414	222	0	0	222	0	0
B.C.	1 479	508	0	3 092	508	0	3 092
Canada	**8 764**	**2 627**	**8 501**	**8 118**	**2 630**	**8 522**	**8 186**

Source: Canadian electric utilities, March 1994

Installed Generating Capacity, Production and Electricity Trade

Table A1.
Installed Capacity and Electrical Energy Consumption in Canada, 1920-1993

	INSTALLED CAPACITY										
	Thermal										
Year	Conventional	Nuclear	Sub-total	Hydro	Total	Electrical Energy Consumption	Average Demand	Peak Demand	Reserve Margin		Load Factor
	(MW)					(GWh) (a)	(MW) (b)	(MW) (c)	(MW) (d)	(%)	(%) (e)
1920	300	-	300	1 700	2 000	-	-	-	-	-	-
1930	400	-	400	4 300	4 700	19 468	2 222	-	-	-	-
1940	500	-	500	6 200	6 700	33 062	3 774	-	-	-	-
1950	900	-	900	8 900	9 800	55 037	6 283	-	-	-	-
1955	2 100	-	2 100	12 600	14 700	81 000	9 247	12 536	2 164	17	74
1960	4 392	-	4 392	18 643	23 035	109 304	12 478	17 264	5 771	33	72
1965	7 557	20	7 577	21 771	29 348	144 165	16 457	24 167	5 181	21	68
1970	14 287	240	14 527	28 298	42 826	202 337	23 098	34 592	8 234	24	67
1975	21 404	2 666	24 070	37 282	61 352	265 955	30 360	46 187	15 165	33	66
1976	23 039	3 466	26 505	39 488	65 993	284 829	32 515	49 527	16 456	33	66
1977	24 699	5 066	29 765	40 810	70 575	299 673	34 209	52 001	18 574	36	66
1978	26 154	5 866	32 020	41 898	73 918	316 435	36 123	54 106	19 812	37	67
1979	27 353	5 866	33 219	44 009	77 228	323 465	36 925	55 699	21 529	39	66
1980	28 363	5 866	34 229	47 770	81 999	340 068	38 821	59 167	22 832	39	66
1981	28 493	5 600	34 093	49 216	83 308	346 333	39 536	59 237	24 071	41	67
1982	28 957	6 547	35 504	50 007	85 511	345 115	39 397	62 417	23 094	37	63
1983	30 447	7 771	38 218	51 274	89 492	359 838	41 077	66 866	22 626	34	61
1984	30 427	9 813	40 240	54 949	95 189	385 516	44 009	65 798	29 391	45	67
1985	30 475	10 664	41 139	55 880	97 019	406 859	46 445	71 235	25 784	36	65
1986	30 979	11 364	42 343	57 731	100 074	423 027	48 153	70 364	29 710	42	68
1987	30 800	12 528	43 328	57 945	101 273	439 710	50 195	77 923	23 350	30	64
1988	30 525	12 593	43 118	57 937	101 055	462 948	52 848	78 961	22 094	28	67
1989	30 892	12 603	43 495	58 465	101 960	474 358	53 971	78 200	23 760	30	69
1990	31 173	13 052	44 225	58 722	102 947	465 395	53 127	78 302	24 645	31	68
1991	32 101	13 052	45 153	60 271	105 424	474 597	54 178	82 963	22 461	27	65
1992	32 720	13 987	46 707	61 993	108 700	476 538	54 399	82 330	26 370	32	66
1993	33 405	15 857	49 262	62 722	111 984	483 610	55 207	86 040	25 944	30	64

(a) 1920-55: Figures are approximate, computed using actual statistics Canada data for stations generating energy for sale to which have been added estimates for stations generating entirely for own use. 1920-55: Canadian Energy Prospects (Royal Commision on Canada's Economic Prospects), John Davis, 1957. 1956-81: Statistics Canada Publication 57-202

(b) Average Demand = Energy Consumption/8760 (hrs/yr).

(c) Statistics Canada Publication, 57-204.

(d) Reserve Margin = (Installed Capacity - Peak Demand) ÷ Peak Demand

(e) Load Factor = Average Demand/Peak Demand

Source: Statistics Canada and Department of Natural Resources Canada

Table A2.
Installed Generating Capacity, 1993

	Hydro	Nuclear	Conventional Thermal	Total	% of Canadian Total
	....................(MW)....................				
Newfoundland	6 650	0	797	7 447	6.65
P.E.I.	0	0	121	122	0.11
Nova Scotia	390	0	1 940	2 330	2.08
New Brunswick	902	680	2 896	4 478	4.00
Quebec	30 065	685	1 530	32 280	28.83
Ontario	720	14 492	14 250	35 951	32.10
Manitoba	4 498	0	412	4 910	4.38
Saskatchewan	836	0	1 942	2 778	2.48
Alberta	823	0	7 558	8 381	7.48
British Columbia	11 223	0	1 743	12 966	11.58
Yukon	77	0	57	134	0.12
N.W.T.	49	0	159	208	0.19
Canada *(totals as of Dec. 31/93)*:	62 722	15 857	33 405	111 984	100.00
Percentage Total:	56.01	14.16	29.83	100.00	
Net Additions during 1993	733	1 870	681	3 284	

Source: Department of Natural Resources Canada

Table A3.
Conventional Thermal Capacity by Principal Fuel Type, 1993* (MW)

Steam					
	Coal	Oil	Gas	Other	Total
Newfoundland	0	543	0	0	543
P.E.I.	0	69	0	0	69
Nova Scotia	1 383	332	0	18	1 733
New Brunswick	703	1 542	0	87	2 332
Quebec	0	737	85	5	827
Ontario	10 628	2 045	537	159	13 369
Manitoba	369	0	4	23	396
Sask.	1 466	21	277	22	1 786
Alberta	5 581	0	1 328	152	7 061
British Columbia	0	63	908	526	1 497
Yukon	0	0	0	0	0
N.W.T.	0	0	0	0	0
Canada	**20 130**	**5 352**	**3 139**	**992**	**29 613**

Gas Turbine			
	Oil	Gas	Total
Newfoundland	170	0	170
P.E.I.	41	0	41
Nova Scotia	205	0	205
New Brunswick	548	0	548
Quebec	577	0	577
Ontario	505	364	869
Manitoba	0	0	0
Sask.	0	155	155
Alberta	0	464	464
British Columbia	100	46	146
Yukon	0	0	0
N.W.T.	0	19	19
Canada	**2 146**	**1 048**	**3 194**

* *Preliminary figures as of December 31, 1993.*
(Numbers may not total due to rounding).

Table A3. continued

Internal Combustion			
	Oil	Gas	Total
Newfoundland	84	0	84
P.E.I.	11	0	11
Nova Scotia	2	0	2
New Brunswick	16	0	16
Quebec	126	0	126
Ontario	4	8	12
Manitoba	16	0	16
Sask.	1	0	1
Alberta	18	15	33
British Columbia	79	21	100
Yukon	57	0	57
N.W.T.	140	0	140
Canada	**554**	**44**	**598**

All Conventional Thermal					
	Coal	Oil	Gas	Other*	Total
Newfoundland	0	797	0	0	797
P.E.I.	0	121	0	0	121
Nova Scotia	1 383	539	0	18	1 940
New Brunswick	703	2 106	0	87	2 895
Quebec	0	1 440	85	5	1 526
Ontario	10 628	2 554	909	159	14 350
Manitoba	369	16	4	23	412
Sask.	1 466	22	432	22	1 942
Alberta	5 581	18	1 807	152	7 558
British Columbia	0	242	975	526	1 743
Yukon	0	57	0	0	57
N.W.T.	0	140	19	0	159
Canada	**20 130**	**8 052**	**4 231**	**992**	**33 405**

** Mainly wood wastes and black liquor.*

Source: Electricity Branch, Natural Resources Canada

Table A4.
Electrical Energy Production by Principal Fuel Type, 1993 (GWh)

	Conventional Thermal*							
	Coal	Oil	Gas	Sub-total	Nuclear	Hydro	Other	Total
Newfoundland	0	1 649	0	1 649	0	39 197	0	40 846
P.E.I.	0	59	0	59	0	0	0	59
Nova Scotia	6 345	2 337	0	8 682	0	879	153	9 714
New Brunswick	1 291	5 232	0	6 523	5 323	3 024	242	15 112
Quebec	0	244	25	269	4 807	149 367	0	154 443
Ontario	18 015	2	3 337	21 354	78 484	40 290	580	140 708
Manitoba	185	12	20	217	0	26 863	41	27 121
Sask.	10 354	43	679	11 076	0	4 057	170	15 303
Alberta	39 351	0	5 809	45 160	0	1 829	1 288	48 277
British Columbia	0	1 191	2 582	3 773	0	53 121	1 692	58 586
Yukon	0	48	0	48	0	287	0	335
N.W.T.	0	237	95	332	0	252	0	584
Canada	**75 541**	**11 054**	**12 547**	**99 142**	**88 614**	**319 166**	**4 166**	**511 088**

	Percentage of Total Generation	Percentage Generated by Utilities	Percentage Generated by Industry
Newfoundland	7.99	98.72	1.28
P.E.I.	0.01	100.00	.00
Nova Scotia	1.90	96.28	3.72
New Brunswick	2.96	95.55	4.45
Quebec	30.19	87.23	12.77
Ontario	27.53	97.49	2.51
Manitoba	5.31	99.75	0.25
Sask.	2.99	97.36	2.64
Alberta	9.45	92.51	7.49
British Columbia	11.46	79.86	22.14
Yukon	0.10	100.00	.00
N.W.T.	0.11	79.45	20.55
Canada	**100.00**	**91.78**	**8.22**

** The conventional thermal breakdown is estimated.*
Source: Statistics Canada and Department of Natural Resources Canada

Table A5.
Provincial Electricity Imports and Exports (GWh), 1989-1993

		Interprovincial Trade			International Trade*			
Province	Year	Exports	Imports	Net Exports	Exports	Imports	Net Exports	Total Net Exports
Newfoundland	1993	30 249	-	30 249	-	-	-	30 249
	1992	25 985	-	25 985	-	-	-	25 985
	1991	26 366	-	26 366	-	-	-	26 366
	1990	26 164	-	26 164	-	-	-	26 164
	1989	24 367	-	24 367	-	-	-	24 367
Prince Edward Island	1993	-	722	-722	-	-	-	-722
	1992	-	738	-738	-	-	-	-738
	1991	-	690	-690	-	-	-	-690
	1990	-	672	-672	-	-	-	-672
	1989	-	622	-622	-	-	-	-622
Nova Scotia	1993	43	241	-198	-	-	-	-198
	1992	67	233	-166	-	-	-	-166
	1991	50	444	-394	-	-	-	-394
	1990	116	365	-249	-	-	-	-249
	1989	341	441	-100	-	-	-	-100
New Brunswick	1993	994	1 258	-264	1 837	121	1 716	1 452
	1992	4 345	3 925	420	1775	116	1 659	2075
	1991	2 542	3 433	-891	3 092	79	3 013	2 122
	1990	2 153	2 775	-622	4 277	162	4 115	3 493
	1989	2 014	2 307	-293	4 640	264	4 376	4 083
Quebec	1993	2 121	30 708	-28 587	13 009	684	12 325	-16 262
	1992	4 509	29 527	-25 018	8 877	1 388	7 489	-17 529
	1991	4 112	27 883	-23 771	5 959	730	5 229	-18 542
	1990	3 349	27 414	-24 065	3 403	1 188	2 215	-21 851
	1989	2 998	25 399	-22 401	5 438	1 001	4 437	-17 964

Table A5. continued

		Interprovincial Trade			International Trade*			
Province	Year	Exports	Imports	Net Exports	Exports	Imports	Net Exports	Total Net Exports
Ontario	1993	435	2 000	-1 565	7 161	2 757	4 404	2 839
	1992	201	2 203	-2 002	5 303	4 166	1 137	-865
	1991	109	2 211	-2 102	4 771	3 674	1 097	-1 005
	1990	140	2 326	-2 186	2 050	13 339	-11 289	-13 475
	1989	91	2 335	-2 244	4 314	7 864	-3 550	-5 794
Manitoba	1993	2 505	909	1 596	7 359	196	7 163	8 759
	1992	3 113	965	2 148	6 250	11	6 239	8 387
	1991	2 634	975	1 659	3 478	289	3 189	4 848
	1990	2 694	1 053	1 641	2 050	991	1 059	2 700
	1989	2 474	1 126	1 348	1 284	1 447	-163	1 185
Saskatchewan	1993	1 331	1 435	-104	229	147	82	-22
	1992	1 083	1 584	-501	138	100	38	-463
	1991	998	1 268	-270	148	120	28	-242
	1990	1 086	1 152	-66	121	107	14	136
	1989	1 130	1 213	-83	72	123	-51	-134
Alberta	1993	1 982	776	1 206	0	2	-2	1 204
	1992	2 016	418	1 598	-	2	-2	1 596
	1991	1 064	678	386	-	3	-3	383
	1990	1 336	500	836	-	3	-3	833
	1989	2 519	258	2 261	-	3	-3	2 258
British Columbia	1993	347	1 958	-1 611	5 251	3 633	1 618	7
	1992	267	1 993	-1 726	9 206	692	8 514	6 788
	1991	655	948	-293	7 070	1 324	5 746	5 453
	1990	461	1 242	-781	6 228	1 991	4 237	3 456
	1989	242	2 477	-2 235	6 341	2 024	4 317	2 082

Table A5. continued

Province	Year	Interprovincial Trade Exports	Interprovincial Trade Imports	Interprovincial Trade Net Exports	International Trade* Exports	International Trade* Imports	International Trade* Net Exports	Total Net Exports
Yukon	1993	-	-	-	-	-	-	-
	1992	-	-	-	-	-	-	-
	1991	-	-	-	-	-	-	-
	1990	-	-	-	-	-	-	-
	1989	-	-	-	-	-	-	-
Northwest Territories	1993	-	-	-	-	-	-	-
	1992	-	-	-	-	-	-	-
	1991	-	-	-	-	-	-	-
	1990	-	-	-	-	-	-	-
	1989	-	-	-	-	-	-	-
Canada	1993	-	-	-	34 846	7 541	27 305	27 305
	1992				31 549	6 476	25 073	25 073
	1991	-	-	-	24 518	6 219	18 299	18 299
	1990	-	-	-	18 130	17 781	349	349
	1989	-	-	-	22 089	12 724	9 365	9 365

** Includes exchanges.*

Source: National Energy Board

Table A6.
Canadian Electricity Exports by Exporter and Importer, 1993*

EXPORTER	IMPORTER	Revenue ($ 000)	Quantity (GWh)
Fraser Inc.	Fraser Paper Ltd. (Maine)	18 157	310
Maine & New Brunswick Electrical Power Co. Ltd.	Maine Public Service Co. (Maine)	2 964	118
NB Power	Houlton Water Co. (Maine)	455	7
NB Power	Maine Public Service Co. (Maine)	3 625	198
NB Power	Eastern Maine Electric Cooperative Inc. (Maine)	3 416	60
NB Power	Maine Electric Power (Maine)	11 433	365
NB Power	Massachusetts Municipal Wholesale Electric Co. (Massachusetts)	38 002	749
Hydro-Québec	Vermont Joint Owners (Vermont)	59 811	955
Hydro-Québec	Vermont Dept. of Public Service (Vermont)	34 222	949
Hydro-Québec	Citizens Utilities (Vermont)	236	6
Hydro-Québec	New England Power Pool (New England)	141 823	6 454
Hydro-Québec	Niagara Mohawk Power Corp. (New York)	11 903	408
Hydro-Québec	New York Power Authority (New York)	83 342	4 236
Canadian Niagara	Niagara Mohawk Power Corp. (New York)	6 352	396
Cornwall Electric	Niagara Mohawk Power Corporation(New York)	447	20
Ontario Hydro	Vermont Dept. of Public Service (Vermont)	7 588	114
Ontario Hydro	Niagara Mohawk Power Corp. (New York)	11 667	443
Ontario Hydro	New York Power Authority (New York)	33 666	1 656
Ontario Hydro	New York Power Pool (New York)	3 534	1 946
Ontario Hydro	Long Island Lighting (New York)	4 390	164
Ontario Hydro	Northeast Utilities (Michigan)	5 872	227
Ontario Hydro	Consolidated Edison (Michigan)	33 432	1 232
Ontario Hydro	Detroit Edison Co. (Michigan)	24 592	960
Ontario Hydro	Minnesota Power and Light	71	3
Manitoba Hydro	Northern States Power Co. (Minnesota)	147 429	3 882
Manitoba Hydro	Otter Tail Power Co. (Minnesota)	4 915	501
Manitoba Hydro	United Power Association (Minnesota)	239	14
Manitoba Hydro	Minnesota Power & Light Co. (Minnesota)	6 807	395
Manitoba Hydro	Minnkota Power Cooperative Inc. (North Dakota)	12 137	705
Sask. Power	Basin Electric Power Cooperative (North Dakota)	3 453	229
Cominco Ltd.	Puget Sound Power & Light Co. (Washington)	174	5
Cominco Ltd	Washington Water Power Co. (Washington)	192	5
Cominco Ltd.	Bonneville Power Administration (Washington)	4 331	120
Cominco Ltd.	Portland General Electric Co. (Oregon)	2 665	73
Cominco Ltd.	Montana Power Co. (Montana)	59	1
B.C. Hydro	Seattle City Light (Washington)	1 112	32
B.C. Hydro	Puget Sound Power & Light Co. (Washington)	369	8
B.C. Hydro	Washington Water Power Co. (Washington)	379	10

Table A6. continued

EXPORTER	IMPORTER	Revenue ($ 000)	Quantity (GWh)
B.C. Hydro	Bonneville Power Administration (Washington)	63 500	3 914
B.C. Hydro	Sierra Pacific Power Co. (Washington)	571	13
B.C. Hydro	Snohomism PUD (Washington)	1 018	24
B.C. Hydro	Eugene Water and Electric (Washington)	5	0
B.C. Hydro	Portland General Electric Co. (Oregon)	38 092	1 008
B.C. Hydro	Montana Power Co. (Montana)	61	2
B.C. Hydro	Pacific Gas & Electric (California)	183	5
B.C. Hydro	Southern California Edison (California)	432	11
B.C. Hydro	Modesto Irrigation (California)	38	1
B.C. Hydro	Hetch Hetchy Water (California)	74	2
B.C. Hydro	Sacramento Municipal Utilities District (California)	34	1
B.C. Hydro	Nevada Power Co. (Nevada)	35	1

** Excludes border accommodations*

Source: National Energy Board

Table A7.
Proposed Generating Capacity Expansion in Canada by Station: Major 1993 Additions

Province and Station	Type*	1993 Additions	Completion Date	Additions Proposed	Status*	Plant Capacity
		(MW)		(MW)		(MW)
NEWFOUNDLAND						
Rose Blanche	H		1995	6	C	6
PRINCE EDWARD ISLAND						
Charlottetown	GT(o)		1996	24	P	24
NOVA SCOTIA						
Point Aconi	S(c)		1994	165	C	
Point Aconi	S(c)		2005	165	P	
New	GT(o)		2004	170	P	170
NEW BRUNSWICK						
Belledune	S(c)	443	2006	440	P	
			2008	440	P	1 283
Combustion Turbine	GT(o)		2001	100	P	100
Combustion Turbine	GT(o)		2004	100	P	100
Combustion Turbine	GT(o)		2005	100	P	100
Combustion Turbine	GT(o)		2006	100	P	100
Combustion Turbine	GT(o)		2009	100	P	100
QUEBEC						
La Forge-1	H	274	1994	4 x 136	C	817
La Forge-2	H		1996	145	C	
			1996	144	P	289
Brisay	H	382				
Outardes 4	H		2002	350	P	350
Outardes 3	H		2002	2 x 239	P	478
Outardes 2	H		2002	282	P	282
Manic-2	H		1999	322	P	1 378
Manic-3	H		1998	2 x 301	P	1 803
Manic-5♦	H	67				
			1994	67	C	2 052

♦*Uprating of existing units*

Table A7.
Proposed Generating Capacity Expansion in Canada by Station: Major 1993 Additions (continued)

Province and Station	Type*	1993 Additions	Completion Date	Additions Proposed	Status*	Plant Capacity
		(MW)		(MW)		(MW)
QUEBEC (cont'd)						
LG-1	H		1994	4 x 100	C	
			1994	2 x 110	C	
			1995	4 x 109	C	
			1995	2 x 110	C	1 312
Ste-Marguerite-3	H		2002	2 x 410	P	820
Grande-Baleine-1	H		2002	2 x 411	P	
			2002	412	P	
			2002	2 x 412	P	2 058
Grande-Baleine-2	H		2003	3 x 180	P	540
Grande-Baleine-3	H		2003	187	P	
			2004	188	P	560
			2004	185	P	
Eastmain-1	H		1999	3 x 155	P	465
Bécancour	H	195			P	
			1993	195	C	390
Rapides-des-Coeurs	H		2000	2 x 174	P	348
Chutes Chaudieres	H		2000	125	P	
			2000	124	P	249
Ashuapmushuan-4	H		2004	730	P	730
Mercier	H		2000	100	P	100
Kipawa	H		2001	115	P	115
ONTARIO						
Darlington	N	1 870				3 524
Big Chute	H	10				
MANITOBA						
Wuskwatim	H		2010	2 x 87.5	P	
			2011	2 x 87.5	P	350
SASKATCHEWAN						
NONE						

Table A7.
Proposed Generating Capacity Expansion in Canada by Station: Major 1993 Additions (continued)

Province and Station	Type*	1993 Additions	Completion Date	Additions Proposed	Status*	Plant Capacity
		(MW)		(MW)		(MW)
ALBERTA						
Genesee	S(c)		1994	406	C	812
Medicine Hat	GT(g)	34				
	S(c)		1996	30	P	30
BRITISH COLUMBIA						
Seven Mile 4	H		2000	1 x 196	P	785
Waneta	H		2003	2 x 190	P	380
Keeneleyside	H		2006	1 x 73	P	240
Brilliant	H		2007	2 x 73	P	450
Revelstoke	H		2005	2 x 450	P	900
Mica	H		2005	2 x 400	P	800
YUKON						
Dawson	IC	1.0	1993			
McIntyre	H		1994	0.8	C	1.5
NORTHWEST TERRITORIES						
Ramkin Inlet	IC	1.0	1993			
Fort Good Hope	IC	0.5	1993			
Yellowknife	IC	3.3	1993			
Arctic Red River	IC	0.2	1993			
Clyde River	IC	0.5	1993			
Aklaaik	IC	0.7	1993			
Arviat	IC	2.0	1993			
Fort Norman	IC		1994	0.5	P	
Baker Lake	IC		1995	1.0	P	

***Legend**

H	Hydro	IC	Internal combustion
S(c)	Steam (coal)	GT	Gas turbine
N	Nuclear	I	Installed
P	Planned	C	Under construction
GT(o)	Gas turbine (oil)		
GT(g)	Gas turbine (natural gas)		

Source: Natural Resources Canada

Federal Environmental Standards and Guidelines

Recent amendments to the National Energy Board Act specify that the Board, in assessing applications for exports and international transmission lines, consider the potential impacts of projects on the environment. (See Chapter 3 for a detailed discussion of the regulatory process.) This appendix provides a brief overview of some federal environmental standards that, in addition to provincial environmental protection measures, may be particularly relevant to the assessment of such impacts.

Federal environmental standards are those that have been authorized or endorsed by the federal government and that apply where a project affects an area of explicit federal jurisdiction, such as navigable waters or migratory birds. Following a general discussion of types of environmental standards, the relevant federal standards are summarized briefly.[1]

Types of Environmental Standards

Environmental standards are norms established with the overall objective of protecting both human and environmental health. For the purposes of this report, the term "environmental standards" will be used as a general reference to all environmental guidelines, objectives, limits, criteria and codes of practice. Federal environmental standards are grouped into three general categories for the purposes of discussion: ambient standards, emission standards and other standards.

[1] *Greater detail on federal legislation, initiatives and standards may be obtained by contacting the Electricity Branch, Department of Natural Resources Canada.*

Ambient Standards

Ambient standards are quantitative or qualitative statements describing a level of environmental quality that, if maintained in the "ambient" or open environment, will normally protect environmental and human health. Such standards generally specify concentrations of substances, or physical characteristics such as water temperature. Federal ambient standards normally have no legal force in themselves. They describe a level of environmental quality that may apply to specific designated regions, or to all regions of Canada. They serve as the goals or objectives towards which pollution-control initiatives, including legislation and regulations specifying emission standards, are directed.

Emission Standards

Emission standards refer to a limit on the quantity or quality of substances that may be released from industrial processes. They usually specify a release rate or maximum concentration of a harmful substance that may be present in the emission as it emerges from its source: a smokestack, pipeline or landfill drainage system. Federal emission standards, which are given force of law under regulations, are considered to be the minimum acceptable requirements for any industrial undertaking. More stringent emission standards may be required to meet appropriate ambient standards at a particular site.

Other Standards

Other standards include programs and legislation that provide for a wide variety of environmental protection measures, in addition to ambient or emission standards. Examples include the Environmental Codes of Practice for Steam Electric Power Generation and the Canadian Environmental Protection Act.

Overview of Federal Standards

1.1 Ambient Standards: Air

National Ambient Air Quality Objectives

The *National Ambient Air Quality Objectives*, published under the authority of the Canadian Environmental Protection Act (CEPA) of 1988, specifies criteria for tolerable, acceptable and desirable levels of sulphur dioxide, nitrogen oxides, particulate matter, ozone and carbon monoxide in the open or ambient atmosphere.

Intergovernmental Agreements

Ambient standards are one method of implementing intergovernmental agreements to reduce and control air pollution. (For a general discussion of intergovernmental agreements on air pollution, see section 3.3 of this appendix.)

1.2 Ambient Standards: Water

Water Quality Guidelines

The Canadian Water Quality Guidelines, published by the Canadian Council of Ministers of the Environment (CCME), is an inventory of "water quality objectives" (ambient standards) suitable for different water uses in Canada, such as aquatic life, industrial processes, human consumption, recreational use and agricultural irrigation. These standards differ depending on the different water uses and must therefore be adapted to meet regional water quality needs. These standards are developed from existing guidelines where appropriate, such as the *Guidelines for Canadian Drinking Water Quality*, established by the Federal-Provincial Subcommittee on Drinking Water.

Intergovernmental Agreements

Canada has entered into an agreement with the United States (The Great Lakes Water Quality Agreement) to restore and maintain the water quality of the Great Lakes basin. To assist in meeting the goals of the Agreement, environmental quality objectives (ambient standards) were established for these waters.

Other regional ambient standards may be developed under federal-provincial agreements and programs enacted pursuant to the Canada Water Act.

2.1 Emission Standards: Air

Thermal Power Generation Emissions -- National Guidelines for New Stationary Sources

These guidelines, published under the authority of CEPA, and revised in 1993, are technology-based air emission standards for new fossil-fuelled electric generating stations. They are generic emission limitations recommended as minimum national standards that should be adopted by utilities and provincial governments. Criteria specified in the guidelines include those for sulphur dioxide, nitrogen oxides and particulate matter emissions, as well as for opacity (visibility standards) and continuous emission monitoring.

2.2 Emission Standards: Water

The Environmental Codes of Practice for Steam Electric Power Generation

See Other Federal Standards, section 3.1, for a general description of the Codes of Practice.

The Design Phase Code of Practice recommends technology-based minimum waste water emission limitations. These standards specify effluent criteria for metals, oil and grease, chlorine, suspended solids and acidity, to minimize the total amount of contaminants discharged to surface waters. These criteria are of concern to aquatic and human life.

Federal Legislation: the Fisheries Act, the Canada Water Act, and the Migratory Birds Act

The Fisheries Act prohibits the deposit of deleterious substances in any waters inhabited by fish. Regulations may limit the deposit of certain types of waste or substances in specific quantities and concentrations. Provisions are supported by Environment Canada's *Environmental Codes of Practice for Steam Electric Power Generation*. The Act also includes a broad range of environmental protection measures that cannot be adequately discussed in this short summary.

The Canada Water Act provides the federal government with the authority to regulate the emission of substances in designated "water quality management" areas. No regulations for water emissions have been implemented under this Act. The Act also provides the federal government with the authority to enter agreements with the provinces for water quality management.

Regulations pursuant to the Migratory Birds Act prohibit, in certain circumstances, the dumping of substances harmful to migratory birds in any water or area populated by these birds in Canada.

Other Federal Standards

3.1 Environmental Codes of Practice for Steam Electric Power Generation

The *Environmental Codes of Practice*, developed by a federal-provincial government and industry task force established by Environment Canada, contain recommendations judged to be reasonable and practical measures that can be taken to preserve the quality of the environment affected by fossil- and nuclear-fuelled electric power generation. Codes of practice have been published for the design, siting, construction, operation and decommissioning phases of steam electric power generation projects. Although the design and siting phase codes have no legal status, the construction, operation and decommissioning phase codes have been published under the authority of CEPA.

The various phases of the codes of practice, although treated in separate documents, are interdependent. To ensure environmental protection throughout the life of a steam electric power generating facility, the Codes should be considered as a whole.

3.2 Federal Legislation for the Control of Harmful Substances

The Canadian Environmental Protection Act provides authority for the control of harmful or toxic substances at any stage of the life-cycle of these substances, including development, manufacturing, storage, transportation, use and disposal. The Act specifies that the Minister of the Environment may develop environmental objectives (ambient standards), release guidelines (emission standards) and codes of practice, as well as enforceable regulations based on these and other environmental standards. Regulations include standards for the storage and disposal of polychlorinated biphenyls (PCBs).

The Transportation of Dangerous Goods Act authorizes the creation and enforcement of safety standards for transport, preparation for transport, and the related handling of dangerous goods (including PCBs and radioactive substances).

The Pest Control Products Act authorizes the development and enforcement of safety standards for the storage, handling and use of pesticides.

3.3 Intergovernmental Air Pollution Agreements

Canada is a signatory to three international protocols of the United Nations Economic Commission for Europe (ECE), under the 1979 Convention on Long-Range Transboundary Air Pollution. The sulphur protocol (1985) commits signatories to reduce national sulphur dioxide emissions by 30 per cent of 1980 levels by 1993. The nitrogen oxides protocol (1988) commits signatories to freeze national nitrogen oxides emissions at 1987 levels by 1994. The protocol on volatile organic compounds (VOCs) (1991) commits signatories to freeze national VOC emissions at 1988 levels by 1999, and, for high ozone regions, to reduce VOC emissions by 30 per cent of 1988 levels by 1999.

The protocol for the reduction of sulphur dioxide emissions has been implemented in Canada by individual agreements between the Government of Canada and the seven easterly provinces, to reduce emissions of sulphur dioxide by approximately 40 per cent of actual 1980 emissions by 1994. Consistent with the international protocol on NOx and VOCs, and with the Canadian goal of reducing ozone levels to the ambient air quality objective of 82 parts per billion, the Canadian Council of Ministers of the Environment (CCME) has developed a comprehensive plan of action for the further management of nitrogen oxides and volatile organic compound emissions in Canada.

On March 13, 1991, the governments of Canada and the United States signed an agreement on air quality (the Air Quality Accord). Among other things, Canada agreed to:

- Cap SO_2 emissions in the 7 easternmost provinces at 2.3 million tonnes per year from 1995 to 1999.
- Achieve a permanent national cap of 3.2 million tonnes per year by 2000.
- Reduce annual emissions of NOx from stationary sources by 100 000 tonnes per year below the year 2000 forecast level of 970 000 tonnes per year.
- Develop, by January 1, 1995, further annual national emission reduction requirements from stationary sources to be achieved by 2000 and/or 2005.
- By January 1, 1995, estimate SO_2 and NOx emissions from each new existing electric utility unit greater than 25 MW, using a method of comparable effectiveness to continuous emission monitoring.
- Assess, notify and mitigate against significant possible transboundary air pollution impacts arising from new projects.

Federal/provincial agreements were renegotiated in 1993 to put the first of the above points into effect.

3.4 General Environmental Standards for Nuclear Power Generation: Atomic Energy Control Board

See Chapter 3 for a general discussion of the regulatory function of the Atomic Energy Control Board (AECB).

The AECB's standards for licensing and monitoring nuclear facilities include regulations pursuant to the Atomic Energy Control Act for limiting radiation dosage to the public, and transportation standards for packaging and marking nuclear substances. The Board receives advice on environmental standards from Environment Canada and frequently conducts its licensing activities under a joint regulatory process involving federal and provincial environment authorities. The AECB coordinates its regulatory activities with the federal Environmental Assessment and Review Process (EARP) and any provincial environ-

mental review process that may be required for nuclear facilities.

3.5 General Environmental Standards for Electricity Generation and Transmission for Export: National Energy Board

See Chapter 3 for details of the National Energy Board's regulatory process.

Applicants for a permit for an export of electricity or for an international transmission line are required to submit information to the National Energy Board on the potential environmental impacts of the export of the line. The Board will apply the procedures specified in the federal EARP Guidelines Order in determining whether to recommend designating an application for the licensing or certification process. When a licence hearing is necessary, applicants may be required to undertake a detailed analysis of the project, including among other things, environmental considerations.

3.6 Federal Environmental Assessment and Review Process Guidelines Order

See Chapter 4 for details of the federal EARP.

The Guidelines Order sets out standard procedures that should be followed by federal government departments in conducting an initial screening of projects under their authority for significant environmental effects.

Prices Paid by Major Electric Utilities for Independent Power Production in 1993

Major Electric Utility	Purchase Rates	Pricing Formula	Remarks
Newfoundland and Labrador Hydro	Isolated Areas: depends on system	Based upon "share the savings" principle up to a maximum of 90% of the avoided fuel cost.	Purchases for isolated areas are evaluated based on the size of the system under consideration.
	Interconnected Areas: Winter (November-March) Capacity: 4.50 ¢/kWh Energy: 3.58¢/kWh Summer (April-October) Capacity: 2.11¢/kWh Energy: 3.58¢/kWh Rates are in 1992$. The capacity rate shall be escalated by the CPI* to the date that the plant goes in service after which it is fixed for the term of the contract. The energy rate shall be escalated by the CPI.	Based upon Average Incremental Cost.	NLH released a "Request for Proposals" for 50 MW of hydraulic IPP** in 1991. Proposals must be small hydro generation projects with capacities not to exceed 15 MW. Projects shall have capacity factors in excess of 40%. Plant's earliest in-service date is late 1997.
Newfoundland Light and Power Co. Ltd.	Negotiable.	Negotiation up to the system incremental cost of generation (total avoided cost).	IPPs will be considered if they are identified as part of an integrated resource plan for the island. Energy from IPPs will be purchased anytime the negotiated price is less than the short-run marginal cost of production (i.e., fuel and variable O&M).
Maritime Electric	3.315¢/kWh (in 1993)	Average purchase price of economy energy from New Brunswick Power.	
Nova Scotia Power	Energy: 2.0¢/kWh	Full avoided cost based on system simulations.	Present forecast shows that NSP does not require additional capacity until sometime beyond 2000. Any new purchase up to this time would receive payments based on avoided energy cost.
NB Power	Non-Dedicated Energy: Rate varies monthly.	Avoided energy costs only.	90% of system decrement.
	Dedicated Capacity: on-peak: 5.5¢/kWh off-peak: 3.3¢/kWh	Avoided full cost.	Dedicated capacity is not available to new NUG until after 2000. Capacity up to 5 MW.

Major Electric Utility	Purchase Rates	Pricing Formula	Remarks
	Capacity: $20.34/kW/mo Energy: 3.1¢/kWh	Avoided full cost but tied to Belledune actual fuel and O&M costs.	Capacity greater than 5 MW
Hydro-Québec	4.65¢/kWh (1994 $)	Avoided cost.	The price is for high tension (greater than 15 MW) and will be adjusted by the Consumer Price Index at a maximum of 6% and at a minimum of 3%.
	4.8¢/kWh (1994 $)	Avoided cost.	The price is for an average tension (less than or equal to 15 MW) and will be adjusted by the Consumer Price Index at a maximum of 6% and at a minimum of 3%.
	3.98¢/kWh (summer 1994) 7.30¢/kWh (winter 1994)	Avoided cost	From renewable sources, 20 years contract, capacity less than or equal to 15 MW.
	4.59¢/kWh (in 1994)	Avoided cost	From renewable sources, capacity less than 10 MW. Capacity factor for 65% to 100%.
Ontario Hydro	Projects up to 5 MW:		
	Option 1 - Basic purchase rate schedule offered to non-utility generators regardless of the fuel or technology used.	Avoided cost.	To qualify for Option 1, a non-utility generator would have to enter into a contract with Ontario Hydro for a typical term of 20 years.
	Winter peak: 6.90¢/kWh	Peak rates are based on Ontario Hydro's 20-year incremental capacity and energy costs.	All time-differentiated rates adjusted annually at Ontario's CPI.
	Winter off-peak: 2.84¢/kWh	Off-peak rates are based on incremental energy cost.	Capacity factor is not a criterion in setting the rates.
	Summer peak: 6.21¢/kWh Summer off-peak: 1.81¢/kWh		
	Option 2 - Premium rates to projects that use renewable resources or use high efficiency energy conversion technology.	In principle, the pricing formula is the same as Option 1 above.	
	Winter peak: 7.29¢/kWh Winter off-peak: 3.01¢/kWh Summer peak: 6.56¢/kWh Summer off-peak: 1.92¢/kWh		

Prices Paid by Major Electric Utilities for Independent Power Production in 1993 (continued)

Major Electric Utility	Purchase Rates	Pricing Formula	Remarks
	Projects delivering over 5 MW net.	Negotiated	To be reviewed project-by-project.
Manitoba Hydro			Additional capacity will not be needed until about the turn of the century.
SaskPower	Rates established by competitive bidding.	Avoided cost.	25 MW of NUG capacity for start-up in 1995.
TransAlta Utilities Alberta Power Edmonton Power and the City of Medicine Hat	5.2¢/kWh (fixed from 1990 to 1994) increasing to 6.0¢/kWh (fixed from 1995 to 1999) or 4.64¢/kWh starting in 1990, escalating with inflation.	Legislated rates.	These rates are applied to small power producers using renewable resources such as wind, hydro and biomass. Projects are up to 2.5 MW. A limited number of pilot projects in excess of 2.5 MW may be approved.
	Energy from non-traditional sources such as generators powered by flare gas or co-generators.	To be negotiated.	
B.C. Hydro	To be negotiated.	80% of B.C. Hydro's avoided cost. The purchase price from an IPP must be less than the cost of other B.C. Hydro options at the time.	Should B.C. Hydro decide to purchase electricity from the private sector, the amount of electricity supply would then be negotiated.
Yukon Energy Corporation		Avoided cost	Interim policy

* CPI = Consumer Price Index
** IPP = Independent Power Producer

Source: Major electric utilities, March 1993

Definitions and Abbreviations

Alternating Current (AC):
A current that flows alternately in one direction and then in the reverse direction. In North America the standard for alternating current is 60 complete cycles each second. Such electricity is said to have a frequency of 60 hertz. Alternating current is used universally in power systems because it can be transmitted and distributed much more economically than direct current.

Base Load:
The minimum continuous load over a given period of time.

British Thermal Unit (BTu):
A unit of heat. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Capacity:
In the electric power industry, capacity has two meanings:

1. System Capacity: The maximum power capability of a system. For example, a utility system might have a rated capacity of 5000 megawatts, or might sell 50 megawatts of capacity (i.e., of power).

2. Equipment Capacity: The maximum power capability of a piece of equipment. For example, a generating unit might have a rated capacity of 50 megawatts.

Capacity Factor:
For any equipment, the ratio of the average load during some time period to the rated capacity.

Cogeneration:
A cogenerating system produces electricity and heat in tandem. Such systems have great potential in industry, where a significant requirement for electricity is coupled with a large demand for process steam.

Consumer Price Index (CPI):
A measure of the percentage change over time in the cost of purchasing a constant "basket" of goods and services. The basket consists of items for which there are continually measurable market prices, so that changes in the cost of the basket are due only to price movements.

Consumption:
Use of electrical energy, typically measured in kilowatt hours.

Conventional Generation:
Electricity that is produced at a generating station where the prime movers are driven by gases or steam produced by burning fossil fuels.

Current:
The flow of electricity in a conductor. Current is measured in amperes.

Demand Charge:
The component of a two-part price for electricity that is based on a customer's highest power demand reached in a specified period, usually a month, regardless of the quantity of energy used (e.g., $2.00 per kilowatt per month). The other component of the two-part price is the energy charge.

Direct Current (DC):
Current that flows continuously in the same direction (as opposed to alternating current). The current supplied from a battery is direct current.

Economy Energy:
Energy sold by one power system to another, to effect a saving in the cost of generation when the receiving party has adequate capacity to supply the loads from its own system.

Electrical Energy:
The quantity of electricity delivered over a period of time. The commonly used unit of electrical energy is the kilowatt-hour (kWh).

Electrical Power:
The rate of delivery of electrical energy and the most frequently used measure of capacity. The basic unit is the kilowatt (kW).

Energy Charge:
The component of a two-part price for electricity which is based on the amount of energy taken (e.g., 20 mills per kWh). The other component of the price is the demand charge.

Energy Source:
The primary source that provides the power that is converted to electricity. Energy sources include coal, petroleum and petroleum products, gas, water, uranium, wind, sunlight, geothermal, and other sources.

Firm Energy or Power:
Electrical energy or power intended to be available at all times during the period of the agreement for its sale.

Frequency:
The number of cycles through which an alternating current passes in a second. The North American standard is 60 cycles per second, known as 60 hertz.

Gigawatt (GW): One billion watts. (See Watt.)

Gigawatt hour (GW.h):
A unit of bulk energy. A million kilowatt hours. A billion watt hours.

Grid:
A network of electric power lines and connections.

Gross Domestic Product (GDP):
The total value of goods and services produced in Canada. GDP measured in constant dollars is defined as Real GDP.

Gross National Product (GNP):
The total value of production of goods and services measured at market prices.

Hertz (Hz):
The unit of frequency for alternating current. Formerly called cycles per second. The standard frequency for power supply in North America is 60 Hz.

Installed Capacity:
The capacity measured at the output terminals of all the generating units in a station, without deducting station service requirements.

Interruptible Energy or Power:
Energy or power made available under an agreement that permits curtailment or interruption of delivery at the option of the supplier.

Joule:
The international unit of energy. The energy produced by a power of one watt flowing for one second. The joule is a very small unit: there are 3.6 million joules in a kilowatt hour.

Kilovolt (kV): 1000 volts.

Kilowatt (kW):
The commercial unit of electric power; 1000 watts. A kilowatt can best be visualized as the total amount of power needed to light ten 100-watt light bulbs.

Kilowatt hour (kWh):
The commercial unit of electric energy; 1000 watt hours. A kilowatt hour can best be visualized as the amount of electricity consumed by ten 100-watt light bulbs burning for an hour. One kilowatt hour is equal to 3.6 million joules.

Load:
The amount of electric power or energy consumed by a particular customer or group of customers.

Load Factor:
The ratio of the average load during a designated period to the peak or maximum load in that same period. (Usually expressed in per cent.)

Megawatt (MW):
A unit of bulk power; 1000 kilowatts.

Megawatt hour (MW.h):
A unit of bulk energy; 1000 kilowatt hours.

Mill: 1/1000 of a dollar.

Net Exports:
Total exports minus total imports.

Nuclear Power:
Power generated at a station where the steam to drive the turbines is produced by an atomic process, rather than by burning a combustible fuel such as coal, oil or gas.

Peak Demand:
The maximum power demand registered by a customer or a group of customers or a system in a stated period of time such as a month or a year. The value may be the maximum instantaneous load or more, usually the average load over a designated interval of time, such as one hour, and is normally stated in kilowatts or megawatts.

Power System:
All the interconnected facilities of an electrical utility. A power system includes all the generation, transmission, distribution, transformation, and protective components necessary to provide service to the customers.

Primary Energy Consumption:
The amount of energy available to the final consumer, plus conversion losses and energy used by the energy supply industries themselves. (Conversion losses are losses in the processing of refined petroleum products, for example, or losses due to thermal and mechanical inefficiencies resulting from the conversion of fossil fuels - coal, oil and natural

gas - into electricity in thermal power generation).

Reserve Generating Capacity:
The extra generating capacity required on any power system over and above the expected peak load. Such a reserve is required mainly for two reasons: (i) in case of an unexpected breakdown of generating equipment; (ii) in case the actual peak load is higher than forecast.

Secondary Energy Consumption:
The amount of energy available to, and used by, the consumer in its final form.

Terawatt Hours (TW.h):
One billion kilowatt hours.

Voltage:
The electrical force or potential that causes a current to flow in a circuit (just as pressure causes water to flow in a pipe). Voltage is measured in volts (V) or kilovolts (kV).
1 kV = 1000 V.

Watt:
The scientific unit of electric power; a rate of doing work at the rate of one joule per second. A typical light bulb is rated 25, 40, 60 or 100 watts, meaning that it consumes that amount of power when illuminated. A horse power is 746 watts.

ELECTRIC POWER IN CANADA 1994

Canadian Electricity Association
Association canadienne de l'électricité

Natural Resources Canada
Ressources naturelles Canada

Canadian Electricity Association

The Canadian Electricity Association (CEA), founded in 1891, is the national forum and voice of the electric utility industry in Canada.

At the heart of CEA is a core of 36 corporate utility member companies accounting for about 95 per cent of Canada's installed generating capacity. In addition, some 34 major Canadian electrical manufacturers and several hundred other company and individual members are grouped within CEA's broad structure.

Mission Statement

- To lead the industry in the identification of potential business issues of national concern and develop through its members policy positions to address these issues. To represent the industry in advocating these policy positions among concerned government, business and societal stakeholders. To raise the awareness of key issues within the industry and the general public. To provide leadership in the formation of coalitions and partnerships to effectively accomplish these objectives.

- To develop and promote programs, standards, information exchange and education opportunities to help members meet their customers' quality and cost expectations, their owners' financial and economic needs, as well as public requirements of health, safety and sustainable development.

- To identify world-class business processes, emerging technological and market developments of potential value to members, and to develop partnerships for their study as well as forums for their transfer to members.

Electric Power in Canada 1994

Corporate Resources,
Canadian Electricity Association

Energy Resources Branch
Energy Sector
Natural Resources Canada

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A Message from the Editor

It has been 30 years since the first edition of Electric Power in Canada (EPIC) was published. Throughout this time, the primary goal of EPIC has remained the same - to provide a comprehensive annual review of development in the Canadian electric power sector, to serve the information needs of government, industry, and the general public. Here at Natural Resources Canada (NRCan), we have relied on the co-operation of many interested parties, most notably the electric utilities themselves, to make EPIC the thorough and useful publication it is.

With our changing times, we are moving into a new type of partnership. The government's budget of February called for a concerted effort across government to help reduce the federal deficit. As part of that broad effort, the budget for EPIC has been eliminated. In consultation with the Canadian Electricity Association (CEA), we have developed a transition plan that will see NRCan and CEA jointly publish EPIC this year. As agreed, NRCan prepared the English and French manuscripts, and CEA undertook the printing. Although copies of EPIC have been available free of charge since the first report in 1964, we find that we must now implement a charge to cover printing costs. CEA will administer the distribution and will send a letter to former recipients of EPIC explaining the policy change. A plan will be developed with CEA to determine how future issues will be published.

As Editor, I am pleased to present the 1994 edition of EPIC, published jointly by the Canadian Electricity Association and Natural Resources Canada.

Po-Chih Lee, Ph.D.
Editor

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Highlights of 1994 Electrical Developments

Electricity Demand

Electricity demand rose only 1.3 per cent in 1994. This small increase was mainly attributed to energy conservation efforts. Although real Gross Domestic Product grew strongly at 4.6 per cent in 1994, it did not produce significant impact on domestic electricity demand. A comparison of electricity demand by province is summarized as follows:

Electricity Demand in Canada (GWh)

Province	1993	1994	% Change
Newfoundland	10 904	10 959	0.5
Prince Edward Island	806	816	1.2
Nova Scotia	9 919	9 974	0.6
New Brunswick	13 873	14 205	2.4
Quebec	170 153	172 172	1.2
Ontario	137 644	137 430	-0.2
Manitoba	18 642	18 901	1.4
Saskatchewan	15 279	15 926	4.2
Alberta	47 240	50 195	6.3
British Columbia	58 908	59 310	0.7
Yukon	335	297	-11.3
Northwest Territories	588	591	0.5
Canada	**484 291**	**490 776**	1.3

Electricity Generation

Electricity generation increased by 4.2 per cent in 1994, much greater than the 1.3 per cent increase for domestic electricity demand. The increase is resulting from a larger number of exports to the United States. Of the total electricity generated in 1994, hydroelectric generation accounted for 61 per cent, nuclear 19 per cent, coal 15 per cent, natural gas 3 per cent, and oil and other source 1 per cent each. Electrical energy production by fuel type and by province in 1994 was as follows:

Electrical Energy Production by Fuel Type and by Province in 1994 (GWh)

Province	Coal	Oil	Gas	Nuclear	Hydro	Other	Total
Nfld.	0	867	0	0	37 538	0	38 405
P.E.I.	0	40	0	0	0	0	40
N.S.	7 160	1 397	0	0	1 048	155	9 760
N.B.	5 273	2 071	0	5 238	2 741	544	15 867
Que.	0	317	25	5 406	157 176	0	162 899
Ont.	14 873	156	3 361	91 086	38 390	567	148 433
Man.	206	6	23	0	28 146	54	28 435
Sask.	11 214	47	639	0	3 393	178	15 471
Alta.	42 478	83	6 629	0	1 809	1 296	52 295
B.C.	0	793	4 749	0	53 979	1 494	61 015
Yukon	0	36	0	0	261	0	297
NWT	0	292	94	0	205	0	591
Canada	**81 204**	**6 105**	**15 495**	**101 730**	**324 686**	**4 288**	**533 508**

Capacity Additions

Because of the anticipated slow growth of the economy, there were only a few capacity additions. A total of 1672 MW was added in 1994. Of this total, 1266 MW was hydro, and 406 MW coal. By the end of 1994, total installed generating capacity by fuel type and by province was as follows:

Installed Generating Capacity by Fuel Type and by Province in 1994 (MW)

Province	Coal	Oil	Gas	Nuclear	Hydro	Other	Total
Nfld.	0	798	0	0	6 650	5	7 453
P.E.I	0	121	0	0	0	0	121
N.S.	1 317	589	0	0	390	18	2 314
N.B.	808	1 883	0	680	903	104	4 378
Que.	0	1 543	101	685	30 581	5	32 906
Ont.	10 653	2 710	846	15 028	7 204	132	36 573
Man.	369	17	4	0	4 498	23	4 911
Sask.	1 766	22	433	0	836	22	3 079
Alta.	5 987	18	1 766	0	823	193	8 787
B.C.	0	227	1 031	0	11 223	528	13 009
Yukon	0	57	0	0	77	0	134
NWT	0	143	20	0	49	0	212
Canada	**20 900**	**8 119**	**4 201**	**16 393**	**63 234**	**1 030**	**113 877**

Electricity Exports to the United States

In 1994, electricity exports to the United States increased 53 per cent over 1993, reaching 44 823 GWh, while imports from the United States decreased 65 per cent to 938 GWh. Exports accounted for 9.2 per cent of Canada's total electricity generation in 1994, up from 5.8 per cent in 1993. Export revenue also increased significantly by 55 per cent, from $858 million in 1993 to $1 332 million in 1994, while import costs decreased from $85 million in 1993 to $45 million in 1994.

Export increases in 1994 occurred mainly in Ontario, Quebec, and British Columbia due to improved water flows in these provinces. An increase in demand for electricity in New York and New England also contributed to the increase in exports.

Capital Investment

Electric utilities spent $7.2 billion on facilities in 1994, accounting for 33 per cent of the total investment in the energy sector and 6 per cent of the total investment in the economy. Of the total, about 41 per cent was for generation, 24 per cent for transmission, 20 per cent for distribution, and 15 per cent for other. As of December 31, 1994, the total outstanding long-term debt of the 15 major electric utilities in Canada was $90 billion. Of this total, about 63 per cent ($57 billion) was borrowed on the domestic market, and 37 per cent ($33 billion) was raised on international markets.

Rate Increases

In 1994, Alberta Power had the largest rate increase at 5.0 per cent, followed by Yukon Energy Corporation at 4.0 per cent. A weighted average for Canada was about 0.8 per cent. This increase was much higher than the Consumer Price Index, which registered an increase of only 0.2 per cent.

Demand-Side Management

It is estimated that about 344 MW of generating capacity and 7 104 GWh of energy were saved due to the implementation of demand-side management (DSM) by electric utilities in 1994. Cumulative generating capacity savings as of December 31, 1994, were about 5 571 MW.

Non-Utility Generation

For non-utility generators (NUG), it is estimated that about 771 MW of generating capacity, mainly cogeneration, was added in 1994, and they sold about 8 346 GWh of energy to the major electric utilities.

Chapter 1

The Electric Power Industry in Canada

Industry Structure

The modern electric utility industry began in the 1880's. It evolved from gas and electric carbon-arc commercial and street lighting systems. Thomas Edison's Pearl Street electricity generating station, which opened on September 4, 1882, in New York City, was the first to introduce the modern electric utility system to the world.

Today electricity is vital to almost every aspect of the Canadian economy and is projected to continue to expand its role over the next ten years. From 1947 to the end of 1994, net electricity generation increased at an annual average rate of 5.2 per cent, compared with real Gross Domestic Product of 4.1 per cent, and total population growth of 1.8 per cent. Canada's electric power industry is made up of provincial Crown corporations, investor-owned utilities, municipal utilities and industrial establishments. The federal role regarding electricity is restricted to nuclear energy and international and interprovincial trade.

Under the Canadian constitution, electricity is primarily within the jurisdiction of the provinces. As a result, Canada's electrical industry is organized along provincial lines. In most provinces the industry is highly integrated, with the bulk of the generation, transmission and distribution provided by a few dominant utilities. Although some of these utilities are privately owned, most are Crown corporations owned by the provinces. The dominant utilities are listed in Table 1.1 and who does what in the electric power industry is summarized in Table 1.2.

Among the major electric utilities, seven are provincially owned, five are investor owned, two are municipally owned, and two are territorial Crown corporations. In 1994, provincial electric utilities owned about 83 per cent of Canada's total installed generating capacity and produced about 78 per cent of total generated electricity. The five investor-owned utilities accounted for 7 per cent of all Canadian electric utility capacity and produced about 9.5 per cent of total electricity. Municipally owned utilities accounted for 1.6 per cent of capacity ownership, and produced 1.4 per cent of total generated electricity. The two territorial Crown corporations accounted for 0.3 per cent and 0.2 per cent of capacity and generation respectively.

In addition to the 16 major electric utilities, there are about 60 industrial establishments generating electricity mainly for their own use. A few also sell energy to municipal distribution systems or utilities. These industries are concentrated in the pulp and paper, mining and aluminum smelting sectors. In 1994, industrial establishments owned about 5.8 per cent of total capacity and produced about 8.1 per cent of total generated electricity in Canada, as shown in Table 1.3.

As well as the major electric utilities and industrial establishments, there are about 364 smaller utilities across Canada, of which 87 per cent are located in Ontario. Most of these small utilities are owned by municipalities. They do not own generating capacity; instead, they usually purchase power from the major utility in their province. Several small investor-owned utilities, however, have their own generating capacity. In 1994, small utilities accounted for 1.3 per cent of total Canadian capacity and produced 1.4 per cent of electrical energy.

During the past few years, some independent power producers (IPP) have also been established across Canada, dedicating their entire electricity generation for sales to major electric utilities. These IPP normally do not have their own service areas. In 1994, IPP owned about 0.9 per cent of Canada's total installed capacity and produced 1.3 per cent of total generated electricity.

Electricity and the Economy

The electric power industry has a significant presence within the Canadian economy. As indicated in Table 1.4, there were almost 91 000 people directly employed by the industry in 1994, (about 0.9 per cent of total Canadian employment), down 3,000 persons from 1993, reflecting the continuous restructuring of Canada's electric power industry in 1994. Total revenue increased to about $27 billion in 1994. Of this total, approximately $1.3 billion or 4.8 per cent came from export earnings. The electric power industry has steadily increased its contribution to Canada's Gross Domestic Product, from 2.3 per cent in 1960, to 2.5 per cent in 1970, to 3.0 per cent in 1980, to 3.3 per cent in 1991, to 3.6 per cent in 1994.

The electric power industry had the largest investment share in the energy sector in 1994, with total capital expenditures of $7.2 billion accounting for about 48 per cent of the total investment in the energy sector, and 6 per cent of the total investment in the economy. Total assets of the industry were about $143 billion in 1994, accounting for about 8.3 per cent of the capital stock of the economy, excluding the residential sector. This reflects the capital-intensive nature of the electric power industry. Hydro-Québec, Ontario Hydro and B.C. Hydro were the three largest electric utilities in Canada and, in terms of assets, ranked second, third, and twelfth respectively among all Canadian companies.

Canadian Electric Utilities

Newfoundland

In Newfoundland, the generation and distribution of electricity is dominated by two utilities, Newfoundland Light & Power Company Limited (NLPC) and Newfoundland and Labrador Hydro (NLH). Together, NLPC and NLH serve about 237 000 customers.
NLPC, an investor-owned utility, is the primary retailer of electricity on the island. NLPC was incorporated in 1966 through the amalgamation of St. John's Electric Light Company Limited, United Towns Electric Company Limited and Union Electric Light and Power Company. Approximately 91 per cent of the company's power supply is purchased from NLH, with the balance generated by its own hydro stations. NLPC is a subsidiary of FORTIS Inc., formed in 1987, which owns and operates subsidiaries that include NLPC, a residential mortgage company, and a property investment company.

NLH is a provincial Crown corporation, whose mandate is to generate and transmit electricity in the province. It was established by an act of the provincial legislature in 1954 and was incorporated in 1975. It is the parent company of a group that includes Churchill Falls (Labrador) Corporation (CFLCo), the Lower Churchill Development Corporation (LCDC), Twin Falls Power Corporation Limited, Gull Island Power Co. Ltd., and the Power Distribution District of Newfoundland and Labrador. NLH has 51 per cent ownership in LCDC; the Government of Canada owns the remaining 49 per cent. Through CFLCo, NLH owns and operates the Churchill Falls plant, one of the largest power facilities in the world. NLH's on-island capacity is generated from oil and hydro sources.

Prince Edward Island

Maritime Electric Company Limited (MECL) is an investor-owned utility that has provided electricity service to Prince Edward Island since 1918. The company owns and operates a fully integrated electric utility system providing for the generation, transmission and distribution of

electricity throughout the island. MECL operates two oil-fired generating plants on the island. MECL used to have a 10 per cent equity interest in New Brunswick Electric Power Commission's coal/oil-fired No. 2 unit located in Dalhousie, N.B., but sold this equity back to N. B. Power in 1994. Two submarine cables link MECL's system with New Brunswick's power grid. MECL is the major distributor on the island, serving about 53 900 customers. A municipal utility in the town of Summerside has its own distribution system and purchases power from MECL.

Nova Scotia

The Nova Scotia Power Corporation (NSPC) was incorporated in 1973. Prior to 1992, it was a provincial Crown corporation producing and distributing electricity throughout the province. However, on January 9, 1992, the Nova Scotia government announced the privatization of this utility in order to release provincial taxpayers from the financial burden associated with NSPC's $2.4 billion debt. An Act respecting the privatization of NSPC was introduced in the provincial Legislature on April 16, 1992, and passed on June 19, 1992. Nova Scotia Power Corporation commenced operation as an investor-owned utility on August 13, 1992. NSPC generates most of its electricity from thermal energy, with more than 76 per cent of the production coming from coal. The utility also maintains hydro-generation and oil-fired facilities, and purchases power from New Brunswick. The largest portion of the province's total production is derived from the Lingan generating station located on Cape Breton Island. In 1994, NSPC served about 411 000 customers.

New Brunswick

The New Brunswick Electric Power Commission (NB Power) was established by an act of the New Brunswick Legislature in 1920. The mandate of NB Power is to generate and distribute power under public ownership to all areas of the province. The utility owns and operates 15 generating stations, and electricity is generated from a balance of nuclear, hydro and thermal sources. NB Power also purchases energy from Quebec. In 1994, NB Power directly provided electricity to 325 000 customers and indirectly served an additional 40 000 customers through sales to two municipal utilities.

Quebec

Hydro-Québec is a Crown corporation, established by the provincial Legislative Assembly in April 1944. It is responsible for the generation, transmission and distribution of most of the electricity sold in Quebec, and also sells and purchases both power and energy under agreement with neighbouring electrical systems in Canada and the United States. Almost all of the electricity generated by Hydro-Québec at its stations throughout the province is from hydraulic sources. The utility currently serves about 3.3 million customers, and ranks among North America's largest electric utilities in terms of assets and volume of sales.

Hydro-Québec has six wholly owned subsidiaries: the Société d'énergie de la Baie James, which carried out the construction of Phase 1 of La Grande complex and which now manages large construction projects for Hydro-Québec; Hydro-Québec International, which provides engineering and consulting services abroad for electric power projects; Cedars Rapids Transmission Company Limited, which owns and operates a transmission line between Quebec and New York State; Somarex Inc., which was created to finance, construct

and operate a transmission line in the State of Maine; Nouveler Inc., which promotes energy efficiency and alternative energy sources; and Société 2312-0843 Quebec Inc., which is a partner in the limited partnership société en commandite HydrogenAL II and which, on January 1, 1990, became a partner in the limited partnerships société en commandite HydrogenAL and société en commandite ArgonAL, whose other partner is Canadian Liquid Air Ltd.

Hydro-Québec has a 34.2 per cent interest in Churchill Falls (Labrador) Corporation Limited, which operates the Churchill Falls power plant. Under the contract, Hydro-Québec buys the bulk of the Labrador station's 5,429 MW output at an average price of 0.3 cents/kWh. It also has a 50 per cent interest in HydrogenAL Inc., HydrogenAL II Inc., and ArgonAL Inc.

By the end of 1994, Hydro-Québec had a total of 83 generating stations: 54 hydroelectric, 28 conventional thermal, and one nuclear. Hydro-Quebec served about 3.3 million customers.

Ontario

Ontario Hydro is a provincially owned corporation, established in 1906 by a special statute of the Province of Ontario. Ontario Hydro is a financially self-sustaining corporation without share capital. Bonds and notes issued to the public are guaranteed by the Province. Under the Power Corporation Act, the main responsibility of Ontario Hydro is to generate, supply and deliver electricity throughout Ontario. It also produces and sells steam and hot water as primary products. Working with municipal utilities and with the Canadian Standards Association, Ontario Hydro is responsible for the inspection and approval of electrical equipment and wiring throughout the province.

Ontario Hydro sells wholesale electric power to 309 municipal utilities, which in turn retail it to customers in their service areas. Ontario Hydro also directly serves about 104 large industrial customers and more than 945 000 small business and residential customers in rural and remote areas. In 1994, more than 3.8 million customers were served by Ontario Hydro and the municipal utilities in the province. Ontario Hydro operates 82 power stations: 69 hydroelectric, 8 conventional thermal, and 5 nuclear. Ontario Hydro also operates an extensive transmission system of about 135 000 km across the province.

The year 1992 marked the beginning of a new era for Ontario Hydro. A number of factors combined to confront the corporation with perhaps the most serious crisis in its 87-year history. Two compelling requirements were brought into focus: one was a need to reduce costs in order to halt spiralling rate increases and to control and reduce the company's indebtedness; and the other was a need to re-structure the corporation to make it more efficient and more competitive.

In Ontario, there are also a number of small regional utilities. An example is Great Lakes Power Limited, a private hydroelectric generation and distribution utility operating in Sault Ste. Marie and west of the Algoma district of Ontario. In 1994, the utility served over 10 000 customers in northern Ontario directly, and another 30 000 indirectly.

Manitoba

The Manitoba Hydro-Electric Board (Manitoba Hydro) is a Crown corporation established in 1949 by the provincial legislature. It has broad powers to provide electric power throughout the province and operates under the 1970 Manitoba Hydro Act. Almost all of the province's electric

power is produced by Manitoba Hydro at its generating stations on the Churchill/Nelson river system in northern Manitoba. Manitoba Hydro distributes electricity to consumers throughout the province, except for the central portion of Winnipeg, which is served by the municipally owned Winnipeg Hydro. Manitoba Hydro and Winnipeg Hydro operate as an integrated electrical generation and transmission system. In 1994, Manitoba Hydro served more than 385 000 customers directly, and Winnipeg Hydro served over 91 000 customers.

Manitoba Hydro produces electricity by operating 12 hydroelectric generating stations, two thermal generating stations, and 13 diesel sites.

Saskatchewan

The Saskatchewan Power Corporation (SaskPower) is a Crown corporation operating under the 1950 Power Corporation Act. Under the Act, the mandate of SaskPower includes the generation, transmission and distribution of electricity. At the end of 1994, the corporation served 409 000 customers with electricity. The bulk of the electricity generated by SaskPower is from thermal sources. In 1994, coal-fired stations produced about 75 per cent of total electricity, followed by hydro at 23 per cent, and natural gas at 2 per cent.

The Shand Power Station (1x300 MW) was completed and began producing electricity in 1992. Shand is one of Canada's most environmentally advanced coal-fired stations.

In 1988, the gas operations of the corporation became separate companies within SaskPower. The parent company of the gas operations is the Saskatchewan Energy Corporation (SaskEnergy). In 1989, SaskEnergy became a totally separate company.

Alberta

There are three major electric utilities in Alberta: TransAlta Utilities Corporation, Alberta Power Limited, and Edmonton Power. Together, they supply about 91 per cent of Alberta's electrical energy requirements. All are linked by a transmission network largely owned by TransAlta. The remaining 9 per cent of Alberta's electrical energy is supplied by industry. Over 90 per cent of the electricity generated by Alberta utilities is produced by large coal-fired generating stations.

TransAlta Utilities Corporation, formerly Calgary Power Limited, is the largest investor-owned electric utility in Canada. The company was incorporated under the laws of Canada and has been engaged in the production and distribution of electricity in the Province of Alberta since 1911. About 60 per cent of the electric energy requirements of Alberta are supplied by TransAlta, to over half of the population. In 1994, more than 327 000 customers were served directly by TransAlta, while another 315 000 customers were served indirectly through wholesale contracts. TransAlta has a number of subsidiaries: TransAlta Resources Corporation, its principal subsidiary, holds investment in non-regulated activities including TransAlta Technologies Inc.; TransAlta Energy Systems Corporation which provides building automation and energy management services across Canada; TransAlta Fly Ash Ltd.; Kanelk Transmission Company Limited; and Farm Electric Services Ltd.

Alberta Power Limited, incorporated in 1972, is another investor-owned electric utility in Alberta, and a subsidiary of Canadian Utilities Limited. The activity of the company is concentrated in east-central and northern Alberta. In 1994, Alberta Power supplied about 19 per cent of total Alberta electricity requirements and served about 153 000 customers.

Edmonton Power has the largest generating capacity of any municipally owned utility in Canada. Since its creation in 1902, Edmonton Power has kept pace with the growth and development of Edmonton. In 1994, the utility produced about 12 per cent of Alberta's electricity requirements and served more than 255 000 customers. In 1992, Edmonton City Council created the Edmonton Power Authority which went into effect on January 1, 1993. The status as an Authority was an interim step in incorporating Edmonton Power as a wholly-owned subsidiary of the city rather than a department of the city. It was felt that Edmonton Power would best serve its customers by operating under subsidiary status.

British Columbia

British Columbia Hydro & Power Authority (B.C. Hydro) was incorporated in 1962 and is a Crown corporation operating in British Columbia. B.C. Hydro provides electrical service throughout the province, with the exception of the southern interior which is served by West Kootenay Power and Light Company, Limited. B.C. Hydro is the third largest electric utility in Canada. It generates, transmits and distributes electricity to more than 1.4 million customers in a service area which contains more than 92 per cent of the population of the province.

In 1988, B.C. Hydro proceeded with a corporate restructuring that resulted in the privatization of its mainland gas operations and its rail operations, and the creation of a number of subsidiaries. B.C. Hydro International Limited provides consulting services in the areas of engineering and utility operations to Canadian and international customers. British Columbia Power Export Corporation (POWEREX) was established to market the province's firm electricity exports. POWEREX negotiates and administers firm export sales agreements with U.S. utilities and purchase agreements with electricity producers, and will make arrangements with Hydro for services such as transmission facilities. Powertech Labs Inc. was formed to provide research, testing and consulting work for electrical technological development. Westech Information Systems Inc. was created in 1989 to offer a wide range of professional services, including the design, development and maintenance of integrated computer systems. Western Integrated Technologies Inc. was also created in 1989 to provide technical support and data processing operations.

West Kootenay Power is an investor-owned utility supplying electric service in the southern interior of British Columbia. The company generates and distributes hydroelectricity directly to more than 74 000 customers in its service area. It also supplies power to seven wholesale customers, who in turn serve almost 38 000 customers. West Kootenay Power is owned by UtiliCorp United Inc. of Kansas City, Missouri.

Yukon

Two utilities provide electrical service to about 12 000 customers in the Yukon. The largest of these, in terms of revenues and generating capacity, is the Yukon Energy Corporation. It is a territorial Crown corporation that has taken over responsibility for the Yukon assets of the Northern Canada Power Commission (NCPC). The Yukon Development Corporation (the parent corporation of the Yukon Energy Corporation) has entered into a five-year management services agreement with the Yukon Electrical Company Limited (YECL). Under the terms of the agreement, YECL will operate the Yukon Energy Corporation's assets, purchase the electricity generated, and distribute it to the Energy Corporation's customers. The Energy Corporation's

customers include all of the Yukon's major industries and 13 per cent of the Yukon's non-industrial customers.

In addition to its responsibilities to the Yukon Energy Corporation, YECL (a subsidiary of Canadian Utilities Limited) also generates and distributes power to its own customers. YECL serves 18 communities in the Yukon, including Whitehorse. It purchases the majority of its electrical requirements from the Yukon Energy Corporation.

Northwest Territories

Electrical service to about 14 000 customers in the Northwest Territories is provided by the Northwest Territories Power Corporation (NWTPC) and Northland Utilities Enterprises Limited (Northland). The largest of these, in terms of revenues and generating capacity, is the NWTPC. It is a territorial Crown corporation, which in 1988 took over responsibility for the Northwest Territories' assets of the NCPC.

NWTPC provides electrical service to 51 communities in the N.W.T. and wholesales hydro-power to Northland.

Northland is an investor-owned utility and is a subsidiary of Canadian Utilities Limited. It provides electrical service to seven communities in the south-western region of the N.W.T.

Tables referred to in this chapter are on the following pages.

Tables & Figures

Table 1.1
Canada's Major Electric Utilities by Province

Province	Electric Utility	Ownership
Newfoundland	Newfoundland and Labrador Hydro Newfoundland Light & Power Company Limited	Provincial Private
Prince Edward Island	Maritime Electric Company Limited	Private
Nova Scotia	Nova Scotia Power Incorporated	Private
New Brunswick	New Brunswick Electric Power Commission	Provincial
Quebec	Hydro-Québec	Provincial
Ontario	Ontario Hydro	Provincial
Manitoba	The Manitoba Hydro-Electric Board City of Winnipeg Hydro-Electric System	Provincial Municipal
Saskatchewan	Saskatchewan Power Corporation	Provincial
Alberta	Alberta Power Limited Edmonton Power TransAlta Utilities Corporation	Private Municipal Private
British Columbia	British Columbia Hydro & Power Authority	Provincial
Yukon	Yukon Energy Corporation	Territorial
Northwest Territories	Northwest Territories Power Corporation	Territorial

Source: Natural Resources Canada

Table 1.2
Electricity in Canada - Who Does What

Function	Provinces	Canada
R&D	Utilities, Canadian Electrical Association	Atomic Energy of Canada Limited (AECL)
Planning	Utilities Governments	
Generation Design	Utilities	Atomic Energy of Canada Limited (AECL)
Generation Operation	Utilities	
Transmission	Utilities	
Distribution	Utilities	
Project Regulation	Regulatory Board or Equivalent	Atomic Energy Control Board (AECB)
Rate Regulation	Regulatory Board or Equivalent	
Export Regulation		National Energy Board
Interprovincial Trade Regulation	Utilities (unwritten rules)	National Energy Board (authority limited)
Environmental Regulation	Provincial Mechanisms	Canadian Environmental Assessment Agency (CEAA)

Source: Natural Resources Canada

Table 1.3
Electrical Capacity and Production by Utilities and Industrial Establishments, 1930-94

Year	Installed Generating Capacity			Energy Production		
	Utilities (%)	Industrial Establishments (%)	Capacity (MW)	Utilities (%)	Industrial Establishments (%)	Generation (GWh)
1930	83	17	5 573	93	7	19 468
1940	84	16	8 104	91	9	33 062
1950	83	17	11 076	88	12	55 037
1960	80	20	23 035	78	22	114 378
1965	82	18	29 348	77	23	144 274
1970	88	12	42 826	84	16	204 723
1975	90	10	61 352	87	13	273 392
1980	92	8	81 999	89	11	367 306
1985	93	7	97 020	92	8	447 182
1988	94	6	101 055	92	8	490 672
1989	94	6	101 960	92	8	482 152
1990	94	6	102 947	91	9	465 744
1991	94	6	105 424	92	8	493 026
1992	94	6	108 700	92	8	501 631
1993	94	6	112 205	92	8	511 769
1994	94	6	113 877	92	8	533 508

Source: Electric Power Statistics, Volume II, Statistics Canada, 57-202, 57-001

Table 1.4
Electric Utility Assets, Revenue and Employees, 1994

Utility	Assets ($ millions)	Revenue ($ millions)	Employees (persons)
Major Utilities:			
Newfoundland and Labrador Hydro	1 602	281	1 167
Newfoundland Light & Power Co. Ltd.	553	345	907
Maritime Electric Co. Ltd.	197	83	191
Nova Scotia Power Corporation*	2 161	708	2 181
New Brunswick Electric Power Commission*	4 342	942	2 470
Hydro-Québec	51 608	7 297	25 406
Ontario Hydro	44 085	8 732	24 607
The Manitoba Hydro-Electric Board*	5 929	925	4 029
City of Winnipeg Hydro-Electric System	135	119	594
Saskatchewan Power Corporation	3 262	810	2 445
TransAlta Utilities	3 745	1 392	1 987
Edmonton Power	1 879	460	1 154
Alberta Power Limited	1 938	595	1 398
B.C. Hydro and Power Authority*	10 453	2 185	6 539
Yukon Energy Corporation*	152	34	96
Northwest Territories Power Corporation*	193	99	310
Other Utilities	10 847	1 879	15 293
Canada	143 081	26 886	90 765

*As at March 31, 1994

Source: Electric utilities' annual reports

Chapter 2

Canadian Electricity in the International Context

World Primary Energy Consumption

This chapter compares Canada's electricity supply, demand, trade, and pricing with those of selected other countries in the world. The data used in this chapter were obtained from reputable sources such as the United Nations' Energy Statistics Yearbook and the International Energy Annual published by the Energy Information Administration of the U.S. Department of Energy. Data on the comparison of electricity prices by sector was taken from an annual survey produced by Energy Resources of Canada's Department of Natural Resources.

During the period 1980-1993, the world's total primary energy consumption (petroleum, natural gas, coal, hydroelectricity and nuclear electricity) has increased steadily at an average annual rate of 1.6 per cent. However, individual primary energy forms grew at different rates: petroleum and coal increased at a rate below average, while natural gas, hydroelectricity and nuclear rose substantially above average.

World consumption of petroleum increased from 63.1 million barrels (about 366 petajoules) per day in 1980 to 66.7 million barrels per day in 1993, with an average annual growth rate of only 0.4 per cent. Petroleum is still the largest component of the world's total primary energy consumption, accounting for about 39 per cent. The slow growth of petroleum demand is mainly attributed to a depressed world economy in general, fuel substitution and conservation efforts.

World consumption of dry natural gas rose from 52.9 trillion cubic feet (about 55 472 petajoules or 1.5 trillion cubic metres) in 1980 to 75.5 trillion cubic feet (2.1 trillion cubic metres) in 1993, an average annual growth rate of 2.8 per cent. The use of natural gas for space heating and power generation has been popular in recent years because of its competitive price and reduced environmental impact.

World consumption of coal rose from 4.2 billion short tons (about 113 000 petajoules) in 1980 to 4.9 billion short tons in 1993 with an average annual growth rate of 1.3 per cent. The four largest consumers in 1993 were: China at 1.27 billion, the United States at 0.93 billion, Russia[1] at 0.34 billion, and Germany at 0.33 million short tons. Because of its emissions problem, the growth of coal demand is expected to remain slow.

World consumption of hydroelectric power increased from 1 766 TWh (about 6 357 petajoules) in 1980 to 2 293 TWh in 1993, with an average annual growth rate of 2.0 per cent. As most of the economical hydro sites have been developed in the world, an increase of hydroelectricity demand is expected to be slow. Canada, the United States, Brazil and Russia were the four largest hydroelectricity consumers in the world in 1993.

World consumption of nuclear energy has grown the fastest during the past 13 years, rising from 684 TWh in 1980 to 2 080 TWh in 1993, with an average annual growth rate of 8.9 per cent, about six times larger than that of the world's total primary energy consumption.

In the primary energy consumption, a great portion of coal consumption is used for baseload electricity generation. The same is true for petroleum and natural gas consumption. However, petroleum is mainly used for peak demand, while natural gas is used for both peak demand and baseload. Because of the difficulty of estimating the portions of petroleum, coal and natural gas used for electricity generation at the world level, it is hard to present the world's total

[1] The former Soviet Union ceased to exist on December 25, 1991.

primary energy consumption delivered in the form of electricity.

Based on the U.S. Department of Energy's estimate, world total net electricity consumption (excluding transmission and distribution losses) rose from 7 408 TWh in 1980 to 10 761 TWh in 1993, an average annual growth rate of 2.9 per cent, much greater than the world's total primary energy consumption of 1.6 per cent registered during the same period 1980-93.

Canada holds a significant place in the world's electric power industry. Canada is not only a world leader in long-distance electric power transmission, but also the largest hydroelectric power producer, an important consumer and a big exporter.

Installed Generating Capacity

During the past 22 years, the growth of Canada's electric power industry has kept in line with the world's electric power industry as a whole. World installed generating capacity rose from 1113 GW in 1970 to 2847 GW in 1992, with an average annual growth rate of 4.4 per cent. While Canada's system increased from 43 GW to 108 GW, with an average annual growth rate of 4.3 per cent during the same period 1970-1992. The main difference between these two systems is that Canada's system is predominately hydro, accounting for 57 per cent of total installed capacity in 1992, and total world generating capacity is predominately conventional thermal, accounting for 65 per cent of the total.

Table 2.1 reports the 20 largest electrical systems in the world, and the world total for all 190 countries and areas. Of this world total, conventional thermal (consisting of installed capacity from coal, oil and natural gas) accounted for 1852 GW (65.1 per cent); hydro 654 GW (23.9 per cent); nuclear 331 GW (11.6 per cent); and geothermal only 10 GW (0.4 per cent).

In 1992, Europe had 36 per cent of the world's total installed generating capacity, followed by North America at 32 per cent, dropping one percentage point from 1991, Asia at 26 per cent, up by three percentage point from 1991, South America at 4 per cent, Africa at 3 per cent and Oceania at 2 per cent.

The U.S. electric power industry was the largest in the world, with a total installed capacity of 752 GW, accounting for 26 per cent of the world total. The Soviet Union was second, with an installed capacity of 344 GW, and Japan was third with 205 GW. The United States led in installed capacity for every fuel type: U.S. conventional thermal accounted for 30 per cent of the world's thermal capacity; hydro for 15 per cent; nuclear for 30 per cent; and geothermal for 50 per cent.

Canada ranked sixth in the world with an installed generating capacity of about 108 GW (behind the United States, Soviet Union, Japan, China and Germany), accounting for 4 per cent of the world total. In terms of fuel type, Canada's hydro capacity is the third largest in the world, next to the U.S. and the Soviet Union. Canada's nuclear capacity is sixth in the world, and its conventional thermal capacity is ninth.

Electricity Generation

World electricity generation grew almost at the same rate as generating capacity has during the past 22 years. World electricity generation increased from 4908 TWh in 1970 to 12 027 TWh in 1992, with an average annual growth rate of 4.2 per cent. Canada's electrical system experienced similar growth patterns as did the world as a whole. Canada's total generation rose from 205 TWh in 1970 to 521 TWh in 1992, with an average annual growth rate of 4.3 per cent. However, hydro was the

main source of generation in Canada, accounting for 62 per cent of the Canadian total, as compared with only 17 per cent for the world total.

In 1992, a total of 12 027 TWh of electricity was generated around the world: conventional thermal, mainly from coal-fired stations, accounted for 7699 TWh (64.0 per cent); hydro 2203 TWh (18.3 per cent); nuclear 2083 TWh (17.3 per cent); and geothermal 42 TWh (0.4 per cent). (See Table 2.2.) Although nuclear accounted for only 11.6 per cent of the world's total capacity in 1992, its energy generation share was 17.3 per cent, indicating that most nuclear stations were operating at a relatively high capacity factor compared with conventional thermal stations and hydro plants.

In 1992, Europe accounted for 35 per cent of the world's total net electricity generation; North America had 31 per cent; Asia had 25 per cent; South America had 4 per cent; Africa had 3 per cent and Oceania had 2 per cent.

About 26 per cent of total world electricity generation took place in the United States in 1992. Its conventional thermal generation was 2187 TWh, accounting for 28 per cent of total world conventional thermal. The United States was also the largest nuclear energy producer in the world in 1992, with a total of 619 TWh or 30 per cent of total world nuclear. As a proportion of total national electricity production, however, France's nuclear generation was the largest at about 73 per cent, followed by Belgium at 60 per cent and Sweden at 44 per cent. Canada's nuclear share was a relatively small 16 per cent. The nuclear shares of the United States and the Soviet Union were 20 per cent and 12 per cent respectively.

Canada's total electricity production ranked sixth in the world (behind the U.S., the Soviet Union, Japan, China and Germany), with total production of 521 TWh or 4 per cent of the world total. However, Canada was the largest hydroelectric power producer in the world with total generation of more than 316 TWh, accounting for about 14 per cent of the world's total hydroelectric generation (Table 2.2).

Per Capita Electricity Consumption

World per capita electricity consumption was 2188 kWh in 1992, down 1.4 per cent from 1991. North America had the highest average of 8680 kWh; followed by Oceania at 7098 kWh; Europe at 5729 kWh; South America at 1593 kWh; Asia at 924 kWh; and Africa at 476 kWh.

Canada's per capita electricity consumption ranked second in the world in 1992 at 18 117 kWh, next only to Norway's 25 382 kWh. As Table 2.3 shows, per capita consumption varies significantly among countries. Norway consumed more than 10 times the world average; Canada more than seven times; and the United States about four times. Nigeria and India's per capita consumption levels were less than 17 per cent of the world average. Although China was the fourth largest electricity producer in the world, its per capita consumption was only 30 per cent of the world average.

Two principal factors contribute to Canada's large per capita consumption of electricity. Abundant water resources have permitted the development of economical hydroelectric power projects in various regions, making electrical energy relatively inexpensive and plentiful. This has led to relatively high electricity consumption among all energy users, and it has led many electricity-intensive industries to locate in Canada. As well, Canada's northerly location means a long and cold winter, resulting in much electricity being used for space-heating purposes. Currently, about 34 per cent of total households in Canada use electricity for space heating.

Total Electricity Consumption Growth

World electricity consumption grew by approximately 1.6 per cent annually between 1989 and 1992. Among various regions, Asia had the highest electricity consumption growth rate, at 8.5 per cent for the period 1989-92. It was followed by South America at 3.6 per cent, Africa at 2.8 per cent, Oceania at 2.3 per cent and North America at 1.3 per cent.

As was pointed out earlier, Asia was the only region in the world with a substantial increase in electrical capacity shares in 1992. This increase was mainly attributed to high electricity demand growth, which was the result of relatively high economic growth in the region.

Table 2.4 reports total electricity consumption growth rates during 1989-92, for the 20 largest electricity producers in the world. In general, most of the countries with high consumption growth rates were developing countries. Many of these countries have been engaged in the industrialization of their economies and, as a result, have increased their electrical energy consumption significantly.

Japan and France were the few developed countries with a high electricity consumption growth rate for the same period. Surprisingly, Canada and Sweden were among the countries with the lowest consumption growth rates in the world during the past four years.

Electricity Trade

Electricity exchanges among countries can provide a wide variety of benefits to the consumers and electric utilities of trading countries. Interconnections improve the economics and security of electricity supply and they reduce the level of capacity needed to meet peak loads. Interconnections also improve the flexibility of electricity supply, making it possible to minimize costs by replacing the highest-cost generation, such as oil-fired generation, with imported hydroelectric energy.

In 1992, a total of 345 TWh of electricity was exported internationally, accounting for about 2.9 per cent of world production (Table 2.5). These exports took place mainly in North America and Europe, where there are extensive interconnections between electrical generating stations.

Europe and North America accounted for 87 per cent of total world electricity exports in 1992. As shown in Table 2.5, France was the largest electricity exporter in the world in 1992, with a total of 59 TWh, accounting for about 17 per cent of total world exports and 13 per cent of its own total production. Germany was second, accounting for 10 per cent and Canada was third with 9 per cent of total world exports. Canada exported 32 TWh of electricity to the United States in 1992.

On the import side, the world total was 337 TWh, accounting for 2.8 per cent of total world consumption in 1992 (Table 2.6). Again, Europe and North America were the major trading areas, accounting for 88 per cent of total world imports.

The United States was the largest electricity importer in 1992, with a total of about 37 TWh or 11 per cent of total world imports and about 1.2 per cent of its own total consumption. Italy was second with 36 TWh or 11 per cent of total world imports. The great majority of U.S. electricity imports came from Canada.

Among the top six electricity exporters in 1992, two were also top importers: West Germany and Switzerland. Canada is usually a net electricity exporter, however, due to meeting emission guidelines and the problems associated with 1992 water flows, Canada

imported a substantial amount of electricity from the United States.

Electricity Prices

A comparison of international electricity prices is difficult because of different rate schedules, consumption levels and national currencies. Nevertheless, a reasonable comparison has been established by using average revenue per kilowatt hour in a given sector, under a certain level of consumption, and by converting to U.S. dollars. For a more accurate comparison, purchasing power parities should be used when converted to U.S. dollars. However, such parities are not available for some countries covered in this study and are therefore not taken into consideration.

Tables 2.7, 2.8 and 2.9 summarize electricity prices by sector for 23 cities in 11 selected countries in the world. The results indicate that Canada's electricity prices are highly competitive in the residential, commercial and industrial sectors relative to other countries.

Tables referred to in this chapter are on the following pages.

Tables & Figures

Table 2.1
International Comparison of Installed Generating Capacity, 1992*

Country	Conventional Thermal	Hydro	Nuclear	Geothermal	Total
		(GW)			
United States	552	96	99	5	752
Soviet Union ⅄	241	65	38	0	344
Japan	131	40	34	0	205
China	120	42	0	0	162
Germany ✦	84	9	22	0	115
Canada	**32**	**62**	**14**	**0**	**108**
France	22	25	58	0	105
India	59	20	2	0	81
United Kingdom	50	4	11	0	65
Italy	42	19	0	1	62
Brazil	7	47	1	0	55
Spain	20	16	7	0	44
Australia	29	7	0	0	36
Sweden	8	16	10	0	34
Poland	29	2	0	0	31
Mexico	19	8	1	1	29
Norway	0	27	0	0	27
South Africa	24	1	1	0	26
Korea, Republic of	15	2	8	0	25
Romania	16	6	0	0	22
World Total**	1 852 (65.1%)	654 (23.9%)	331 (11.6%)	10 (0.4%)	2 847 (100.0%)

* Includes the 20 countries with the largest electrical systems.
** Total for all 190 countries or areas listed in source reference.
⅄ The former Soviet Union ceased to exist on December 25, 1991.
✦ Represents a unified Germany.

Source: Energy Statistics Yearbook, 1992, United Nations, pp. 332-360.

Table 2.2
International Comparison of Electricity Generation by Fuel Type, 1992*

Country	Conventional Thermal	Hydro	Nuclear	Geothermal	Total
		(TWh)			
United States	2 187	249	619	20	3 075
Soviet Union ⅄	1 266	235	212	0	1 713
Japan	580	90	223	2	895
China	622	132	0	0	754
Germany ✦	357	21	159	0	537
Canada	**124**	**316**	**81**	**0**	**521**
France	51	73	338	0	462
India	251	70	7	0	328
United Kingdom	240	7	79	1	327
Brazil	16	223	2	0	241
Italy	177	46	0	3	226
South Africa	164	1	4	0	169
Australia	144	15	0	0	159
Spain	82	21	56	0	159
Korea, Republic of	86	5	57	0	148
Sweden	8	75	63	0	146
Poland	129	3	0	0	132
Mexico	92	21	4	5	122
Norway	0	117	0	0	117
Netherlands	73	0	4	0	77
World Total**	7 699	2 203	2 083	42	12 027
	(64.0%)	(18.3%)	(17.3%)	(0.4%)	(100%)

* Includes the world's 20 largest electrical energy producers.
** Total for all 190 countries or areas listed in source reference.
⅄ The former Soviet Union ceased to exist on December 25, 1991.
✦ Represents a unified Germany.

Source: Energy Statistics Yearbook, 1992, United Nations, pp. 392-420.

Table 2.3
International Comparison of Per Capita Electricity Consumption, 1992*

Country	kWh/Person	As Percentage of World Average
Norway	25 382	1 160
Canada	**18 117**	**828**
Iceland	17 465	798
Sweden	16 655	761
Luxembourg	13 693	626
Finland	13 144	601
United States	12 160	556
New Zealand	9 051	414
Australia	9 043	413
Switzerland	8 015	366
Belgium	7 240	331
Japan	7 192	329
France	7 140	326
Austria	6 653	304
Germany✦	6 627	303
United Kingdom	5 933	271
Soviet Union▲	5 818	261
Netherlands	5 666	259
Spain	4 071	229
Italy	4 525	207
South Africa	3 605	165
Korea, Republic of	3 348	153
Argentina	1 778	81
Brazil	1 722	79
Mexico	1 369	63
Egypt	821	38
China	650	30
India	374	17
Nigeria	101	5
World Average**	2 188	100

* The first ten countries are listed according to their actual global rankings. The remaining countries are given in descending order of consumption; however, since only the most populous countries from each region were selected, the list does not indicate their true global rankings.

** Average for all 190 countries or areas included in source reference.

✦ Represents a unified Germany.

▲ The former Soviet Union ceased to exist on December 25, 1991.

Source: Energy Statistics Yearbook, 1992, United Nations, pp. 422-436

Table 2.4
International Comparison of Total Electricity Consumption Growth Rates, 1989-92

Country	Average, 1989-92
Thailand	14.8
Malaysia	14.7
Korea, Republic of	13.1
Jordan	8.8
China	8.0
India	6.8
Japan	3.9
France	3.9
Spain	2.9
Brazil	2.9
Italy	2.8
Australia	2.7
Norway	1.6
United States	1.5
Mexico	1.1
United Kingdom	1.1
South Africa	0.6
Canada	**0.4**
Sweden	0.2
Poland	-4.3
Romania	-11.6
World Total*	1.6

* Total for all 190 countries or areas included in source reference.

Source: Calculated from Energy Statistics Yearbook, 1992, United Nations, pp. 422-470.

Table 2.5
International Comparison of Electricity Exports, 1992*

Country	Exports** (GWh)	Production (GWh)	Percentage of Exports to Production
France	58 533	462 263	12.7
Germany✦	33 738	537 134	6.3
Canada	**31 528**	**520 857**	**6.1**
Switzerland	26 046	59 117	44.1
Sweden	10 995	146 245	7.5
Lithuania	10 642	18 707	56.9
Norway	10 103	117 682	8.6
Poland	9 066	132 750	6.8
United States	8 855	3 074 504	0.3
Austria	8 621	51 180	16.1
South Africa	6 185	169 145	3.7
Belgium	5 721	72 259	7.9
Hong Kong	4 963	34 914	14.2
Denmark	4 901	30 849	15.9
Spain	3 710	158 505	2.3
Estonia	3 492	11 831	29.5
Uraguay	3 396	8 898	38.2
Czech	3 340	59 132	5.6
Mexico	2 042	121 762	1.7
Hungary	1 521	31 614	4.8
Zambia	1 500	7 780	19.3
Portugal	1 197	30 087	4.0
Italy	647	226 243	0.3
Total World Exports***	345 460	12 026 747	2.9

* Includes the world's 25 largest electricity exporters.
** Includes non-cash exchanges.
*** Total for all exporting countries or areas listed in source reference.
✦ Represents a unified Germany.

Source: Energy Statistics Yearbook, 1992, United Nations, pp. 422-436.

Table 2.6
International Comparison of Electricity Imports, 1992*

Country	Imports** (GWh)	Consumption (GWh)	Percentage of Imports to Consumption
United States	37 204	3 102 853	1.2
Italy	35 947	261 543	13.7
Germany✦	28 418	531 814	5.3
Brazil	24 148	265 381	9.1
Switzerland	21 757	54 828	39.7
United Kingdom	16 725	343 572	4.9
Belarus	13 762	37 600	36.6
Austria	9 175	51 734	17.7
Finland	9 067	65 825	13.8
Netherlands	8 905	85 880	10.3
Sweden	8 845	144 095	6.1
Denmark	8 647	34 595	25.0
Canada	**6 477**	**495 806**	**1.3**
Belgium	5 849	72 387	8.1
Lithuania	5 338	13 403	39.8
Poland	5 034	128 718	3.9
Hungary	4 987	35 080	14.2
China	4 980	758 920	0.7
France	4 737	408 467	1.2
Maldova	4 609	11 221	41.1
Luxembourg	4 511	5 176	87.2
Romania	4 421	58 398	7.6
Spain	4 351	159 146	2.7
Bulgaria	3 289	38 292	8.6
Portugal	2 538	31 428	8.1
Total World Exports***	337 038	12 018 325	2.8

* Includes the world's 25 largest electricity importers.
** Includes non-cash exchanges.
*** Total for all importing countries or areas listed in source reference.
✦ Represents a unified Germany.

Source: Energy Statistics Yearbook, 1992, United Nations, pp. 422-436.

Table 2.7
International Comparison of Electricity Prices in the Residential Sector, January 1995

City	Country	Residential Prices (U.S. cents/kWh)
Brussels	Belgium	15.24
New York	United States	14.96
Paris	France	14.64
Madrid	Spain	14.04
Sao Paulo	Brazil	13.80
Boston	United States	12.32
London	United Kingdom	11.97
Chicago	United States	11.57
Detroit	United States	10.52
Singapore	Singapore	9.90
Taipei	Taiwan	9.79
Houston	United States	8.98
Bankok	Thailand	8.86
Minneapolis	United States	7.83
Toronto	**Canada**	**7.39**
Ottawa	**Canada**	**5.62**
Portland	United States	5.60
Sydney	Australia	5.41
Calgary	**Canada**	**5.25**
Vancouver	**Canada**	**4.96**
Montreal	**Canada**	**4.91**
Winnipeg	**Canada**	**4.82**
Seattle	United States	4.41

Source: Canadian data were obtained from the Electricity Branch, Department of Natural Resources Canada. Data for other countries were obtained from a survey undertaken by the Electricity Branch, Natural Resources Canada, February 1995.

Table 2.8
International Comparison of Electricity Prices in the Commercial Sector, January 1995

City	Country	Commercial Prices (U.S.cents/kWh)
New York	United States	15.42
Brussels	Belgium	14.38
Madrid	Spain	11.11
Detroit	United States	11.10
London	United Kingdom	11.08
Boston	United States	10.70
Chicago	United States	9.67
Paris	France	8.86
Sydney	Australia	8.78
Taipei	Taiwan	8.56
Sao Paulo	Brazil	8.19
Bangkok	Thailand	8.19
Toronto	**Canada**	**8.00**
Singapore	Singapore	8.00
Houston	United States	7.95
Montreal	**Canada**	**6.59**
Minneapolis	United States	6.54
Calgary	**Canada**	**6.05**
Ottawa	**Canada**	**5.81**
Portland	United States	5.32
Seattle	United States	5.18
Winnipeg	**Canada**	**5.14**
Vancouver	**Canada**	**4.76**

Source: Canadian data were obtained from the Electricity Branch, Department of Natural Resources Canada. Data for other countries were obtained from a survey undertaken by the Electricity Branch, Natural Resources Canada, February 1995.

Table 2.9
International Comparison of Electricity Prices in the Industrial Sector, January 1995

City	Country	Industrial Prices (U.S. cents/kWh)
Brussels	Belgium	11.91
New York	United States	10.50
London	United Kingdom	9.70
Madrid	Spain	8.55
Boston	United States	8.01
Detroit	United States	7.42
Bankok	Thailand	7.33
Paris	France	7.29
Singapore	Singapore	7.10
Taipei	Taiwan	6.85
Sao Paulo	Brazil	6.63
Chicago	United States	6.58
Houston	United States	6.36
Toronto	**Canada**	**6.10**
Sydney	Australia	5.52
Minneapolis	United States	4.97
Ottawa	**Canada**	**4.88**
Calgary	**Canada**	**3.96**
Vancouver	**Canada**	**3.96**
Seattle	United States	3.91
Portland	United States	3.90
Montreal	**Canada**	**3.84**
Winnipeg	**Canada**	**3.39**

Source: Canadian data were obtained from the Electricity Branch, Department of Natural Resources Canada. Data for other countries were obtained from a survey undertaken by the Electricity Branch, Natural Resources Canada, February 1995.

Regulatory Structures

Federal Regulation

The Constitutional Framework

Canada is a federal state. The power to make laws is divided between the federal government and the provincial governments. Each level of government has independent authority, set out in the *Constitution Act, 1867*, to make laws in certain areas. Within its own area of authority, each level of government is autonomous.

The *Constitution Act, 1867*, divides legislative power between the Parliament of Canada and provincial legislatures. It states that each legislative body may make laws relating to certain classes of subjects. This distribution of powers is listed in sections 91 and 92 of the Act, supplemented by section 92A, which was added in 1982.

Generally speaking, the classes of powers listed in sections 91 and 92 do not overlap: a particular class is assigned to either the Parliament of Canada or to the provinces but not to both. The *Constitution Act, 1867*, can be thought of as defining two mutually exclusive domains of legislative authority.

There are two important qualifications to this exclusivity: in certain areas concurrent powers are assigned to both levels of government, in other areas, each level may have authority to enact laws, based on its list of powers. If there is a direct conflict between the federal and provincial laws in either case, the federal law is paramount.

Energy is not specifically mentioned in sections 91 and 92, although it is referred to in section 92A. Laws that purport to regulate one or another aspect of energy production, transportation, and utilization thus derive their constitutional validity from two sources: (i) those parts of section 91 and 92 that are relevant to the specific energy activity in question, and (ii) section 92A, which deals specifically with natural resources and electrical energy.

Electricity generation systems mostly fall within provincial jurisdiction; they are "local works and undertakings" under section 92(10) of the *Constitution Act, 1867*. Section 92A(1)(c) reinforces this principle. It assigns to the provinces explicit responsibility for "sites and facilities in the province for the generation and production of electrical energy."

The only exception to the above is nuclear power. In 1946, with the passage of the *Atomic Energy Control Act,* the Canadian Parliament declared that all works and undertakings for the production, use and application of atomic energy are for the general advantage of Canada. The effect of this declaration was to place nuclear generation facilities within Canadian government jurisdiction, under sections 92(10)(c) and 91(29) of the *Constitution Act, 1867*. (Section 91(29) assigns to the Parliament of Canada all classes of subjects not exclusively assigned to the provinces. Section 92(10)(c) states that the provinces will not have jurisdiction over local works and undertakings declared by Parliament to be for the general advantage of Canada.)

Jurisdiction over international and interprovincial transmission systems derives from sections 92(10)(a) and 91(29). Section 92(10) assigns general responsibility for "local works and undertakings" to the provinces. It then goes on to list certain exceptions. One exception, stated in section 92(10)(a), is any work or undertaking connecting one province to another or extending beyond the limits of a province. Section 91(29) states that any class of subject not assigned exclusively to the provinces shall be within the power of the Canadian Parliament. Thus the effect of sections 92(10)(a) and 91(29) taken together is to confer upon the Parliament of Canada exclusive legislative authority over transportation undertakings that cross interprovincial boundaries or the international boundary.

Provincial authority over interprovincial transmission systems derives from section 92(10), which allocates to the provinces authority over works and undertakings that are solely provincial in nature.

Section 91(2) confers upon the Parliament of Canada exclusive legislative authority on matters relating to "the regulation of trade and commerce." This is the primary basis upon which the Canadian government regulates electricity exports. Federal jurisdiction over electricity exports may also be derived from sections 92(10) and 91(29), which enable the Parliament of Canada to legislate with respect to international undertakings; this power extends to the marketing of the products transported by such undertakings.

With regard to the regulation of interprovincial electricity sales, the *Constitution Act, 1867* defines concurrent powers. Federal authority is derived principally from the trade and commerce power, section 91(2). Provincial authority derives from section 92A(2), which gives the provinces the power to make laws respecting the export of energy to other parts of Canada, provided that such laws do not discriminate with respect to price or to supply. If a conflict between federal and provincial laws over interprovincial trade should arise, the federal law will prevail. Federal paramountcy in this regard is explicitly stated in section 92A(3).

The above brief summary of the constitutional principles governing electricity in Canada indicates quite clearly that the powers of the Parliament of Canada, extensive though they may be on matters of trade, are quite limited insofar as electricity matters generally are concerned. The constitution assigns to the provinces exclusive jurisdiction over electricity matters that are wholly intraprovincial in nature, and it assigns to the provinces concurrent powers with respect to interprovincial trade. Furthermore, it is the ability of the provincial utilities to enter into purchase and sales agreements, combined with the electricity supply policies of the provincial governments, that primarily determine both the nature and the extent of Canadian electricity trade. The Canadian government, if it is to achieve policy objectives relating to electricity, can therefore achieve very little by acting unilaterally. First and foremost, it must seek provincial consensus and provincial cooperation.

Based on the above-mentioned constitutional framework, two federal regulatory agencies have been established to regulate electricity trade and nuclear energy. Environmental matters related to energy projects are handled by Environment Canada. Provincial regulatory agencies have also been established to implement regulation on electrical energy demand, supply, pricing, and environment assessment on power projects in the provinces.

National Energy Board

The National Energy Board (NEB) is a federal tribunal, created in 1959 by an Act of Parliament. The Board's powers and duties are derived from the *National Energy Board Act*. Under the Act, the Board advises the federal government on the development and use of energy resources, and regulates specific matters concerning oil, gas and electricity. The Board's jurisdiction over electrical matters is limited to the certification of international and designated interprovincial power lines and the licensing of electricity exports from Canada. The Board has no jurisdiction over imports of electricity.

On September 6, 1988, a new policy concerning the regulation of electricity exports and international power lines was announced. Legislation amending the *NEB Act* to give effect to this policy (Bill C-23) was proclaimed on June 1, 1990.

Under the new policy, the Government of Canada will continue to authorize international power lines and exports of electricity. Such authorizations will be of two kinds: (i) permits, which will not require a public hearing or

Governor in Council approval; or (ii) licenses (in the case of electricity exports) or certificates (in the case of power lines), which will require a public hearing and Governor in Council approval.

Authorizations will normally be by an NEB-issued permit unless the Governor in Council, on the advice of the Board, designates the application for certification or licensing. Designations are not likely to occur, except in cases where there is evidence that the export applicant has not taken into consideration (a) the effect of the exportation of the electricity on provinces other than that from which the electricity is to be exported; (b) the impact of the exportation on the environment; and (c) whether the applicant has offered electricity to be exported to domestic buyers under the same terms and conditions.

Once an application is designated, the Board will conduct a public hearing, and it will not issue a license or certificate unless it is fully satisfied that the proposal is in the Canadian public interest. Licenses and certificates will not be issued unless they are also approved by the Governor in Council.

Under the amendments to the *NEB Act*, Part III.1 provides for the federal regulation of international power lines. In determining whether to recommend to the Governor in Council designation of a power line, the Board will have regard to all relevant considerations, including: (i) the effect of the power line on other provinces; (ii) the impact of construction and operation of the power line on the environment; and (iii) any other matters that may be specified in the regulations.

In making its determination, the Board will seek to avoid the duplication of measures taken by the applicant and the relevant provincial government(s). The NEB will continue to authorize the general corridor through which an international power line will pass. However, the precise location of the line within this corridor will normally be determined by provincial regulatory procedures, and any expropriation that may be necessary will be done under provincial laws. The only exception to this general procedure will be in cases where the applicant elects to have federal law apply.

The Governor in Council may by order, designate a particular interprovincial power line for regulation in the same manner as international power lines. When power from one province simply enters the grid of another province, there is no federal regulation.

Part VI of the amended *NEB Act* includes a Division II, which provides for the regulation of electric power exports. The maximum duration of export licenses and permits will be 30 years. In determining whether to recommend to the Governor in Council designation of an application for export, the board will have regard to all relevant considerations, including: (i) the effect of the export on provinces other than that from which the electricity is to be exported; (ii) whether those wishing to buy electricity for consumption in Canada have been granted fair market access to the electricity proposed for export; (iii) the impact of the export on the environment; and (iv) any other matters that may be specified in the regulations. In making its determination, the Board will also seek to avoid the duplication of measures taken by the applicant and the sponsoring provincial government.

Atomic Energy Control Board

Immediately after World War II, Canada began to study the question of how to encourage the use of nuclear energy for peaceful purposes. In 1946, Parliament passed the *Atomic Energy Control Act* with this objective in mind.

The Act gave the federal government control over the development, application and use of nuclear energy and established the Atomic Energy Control Board (AECB). The five-member Board administers and enforces the Act, from which it derives its authority to regulate the health, safety, security and

environmental aspects of nuclear energy. The AECB reports to Parliament through a designated Minister, currently the Minister of Natural Resources Canada.

The Board's primary function is to license Canadian nuclear facilities and activities dealing with prescribed substances and equipment. Nuclear facilities include power and research reactors, uranium mines and refineries, fuel fabrication plants, heavy water plants, waste management facilities and particle accelerators. Prescribed substances include uranium, thorium, heavy water and radioisotopes. Activities relating to such substances, which may be licensed, include production, processing, sale, use, import and export. Before issuing a licence, the AECB ensures that the appropriate health, safety and security standards are met.

The AECB's control also extends to international security of nuclear materials and technology. Through the licensing process, it ensures that nuclear equipment and supplies are exported only in accordance with Canada's obligations under the Treaty on the Non-Proliferation of Nuclear Weapons.

Provincial Regulation

As noted above, under the Canadian Constitution the provinces have legislative authority over the generation, transmission and distribution of electricity. In most provinces some form of regulation exists, and most provinces have established regulatory bodies to oversee the utilities, although the degree of supervision varies. The major areas subject to review are rate-setting and the construction of new facilities. The nature of provincial regulation with respect to these matters is described briefly below. The environmental regulations of the provinces are described in Chapter 4.

Newfoundland

Newfoundland Light & Power Company (NLPC) and Newfoundland and Labrador Hydro (NLH) are regulated by the Newfoundland Board of Commissioners of Public Utilities. The Board fully regulates the rates and policies of NLPC, including the construction of new facilities. Since 1977, the Board has also had authority under the *Electric Power Control Act* to review NLH's rates for residential customers. The Board makes recommendations to the Newfoundland Cabinet, which is the final authority for utility rates.

Cabinet is also the final authority with respect to NLH's capital expenditure program. Proposals by NLH for new facilities must receive Cabinet approval before construction can begin. NLPC must receive the approval of the province's Board of Commissioners of Public Utilities before proceeding with the construction of new facilities.

Prince Edward Island

Maritime Electric Company Limited is regulated by the Island Regulatory and Appeals Commission of Prince Edward Island (formerly the Public Utilities Commission of Prince Edward Island) under the provisions of the *Electric Power and Telephone Act*. The Commission has decision-making authority over electric utility rates in the province and screens all proposals for the construction of new generation and transmission facilities. If the Commission believes that a new facility may adversely affect the environment, a formal environmental assessment review process is initiated. A description of this process is provided in Chapter 4.

Nova Scotia

Since 1976, the Nova Scotia Board of Commissioners of Public Utilities, in accordance with the provincial *Public Utilities Act*, has had full decision-making power over the utility's rates and policies.

The Board's authority extends to the construction of new facilities, and utilities are required to apply directly to the Board when planning new generation or transmission facilities. As part of the review process, the Board holds public hearings, during which the utility presents its proposed project, costs and alternative plans. Members of the public may intervene directly during a hearing. The Board of Commissioners is the final authority on new facilities.

Nova Scotia Power Corporation was privatized in August 1992 changing its name to Nova Scotia Power Incorporated (NSPI). However, the Nova Scotia Public Utilities Board, in accordance with the *Public Utilities Act*, remains the final authority regarding NSPI's rates and development plans.

New Brunswick

As a Crown corporation, New Brunswick Power reports to the provincial government through its chairman, who is a member of the Cabinet. Rates and operations are regulated by a nine-member Board of Commissioners appointed by the Lieutenant Governor of New Brunswick. The utility's chairman and vice chairman sit on the Board. The Board's recommendations are referred to the provincial Cabinet, which is the final regulatory authority. A bipartisan Crown corporation committee also reviews utility rates and operations annually.

NB Power must receive approval from Cabinet before proceeding with the construction of new facilities. Although Cabinet is the final authority in this regard, its decision is based upon a recommendation from the Minister of Municipal Affairs and Environment, following an evaluation of the project's possible environmental impacts. New Brunswick's environmental impact assessment process is described in Chapter 4.

Quebec

In Quebec, the National Assembly's committee on economics and employment reviews Hydro-Québec's long-term development plan, which includes any proposed rate changes. The committee then makes a recommendation to the Minister of Energy and Resources, who in turn makes a recommendation to Cabinet. Rate increases can therefore be implemented by Hydro-Québec only after they have been approved by Cabinet.

The construction of new facilities by Hydro-Québec can take place only after the utility has received an Order-in-Council from the provincial government. Before an Order is issued, the Department of the Environment and the Department of Energy and Resources must approve plans for the new facility. Other departments and agencies are also consulted.

Ontario

Ontario Hydro is a provincially owned corporation, which reports to the government through the Minister of Energy. The management of Ontario Hydro is under the direction and control of its Board of Directors. Proposed rate changes are referred to the Ontario Energy Board (OEB), through the Minister of Energy, for examination at public hearings. However, it is the Board of Ontario Hydro that is authorized to set the utility's rates, and it may accept or reject the recommendations of the OEB.

On matters concerning its generation expansion program and transmission facilities, Ontario Hydro is regulated by the provincial Joint Hearing Board. The Board is composed of members from the Environmental Assessment Board and the Ontario Municipal Board. The Joint Board makes a recommendation to the provincial government, and final approval must be given through an Order-in-Council.

Manitoba

Under the *Manitoba Crown Corporations Public Review and Accountability Act* of 1988, Manitoba Hydro's proposed changes to domestic rates must be reviewed by the Manitoba Public Utilities Board, which holds a public review and makes a final decision on the proposal.

Under the 1988 *Manitoba Environment Act*, the provincial government must also approve major facility construction. Applications are made to the Minister of the Environment and a full environmental assessment is required. A description of Manitoba's environmental assessment review process is given in Chapter 4.

Saskatchewan

Saskatchewan Power Corporation (SaskPower) is governed by a government-appointed Board of Directors that is responsible for the management and operation of the Crown utility. Proposals to increase rates or construct new generation or transmission facilities must be approved by the Board of Directors. The minister responsible for SaskPower is a member of the Board.

Alberta

TransAlta Utilities Corporation and Alberta Power Limited are investor-owned electric utilities in Alberta. They are regulated by the Alberta Energy Resources Conservation Board (ERCB) with respect to the development of generation and transmission facilities, coal mine developments and changes in service areas. Thermal generating stations are issued permits, which are subject to Lieutenant Governor in Council approval, while hydro dam approvals require final authorization through the passage of a bill in the legislature. TransAlta's and Alberta Power's rates are regulated by the Alberta Public Utilities Board, under the provisions of the *Public Utilities Board Act* of 1980.

As a municipally owned utility, Edmonton Power is subject to the authority of Edmonton Council, as well as the various provincial regulatory bodies. Its rates and financing are regulated by city council, while the ERCB is responsible for the regulation of new generation and transmission facilities.

Since February 1995, electricity regulatory structure has changed in Alberta. The Alberta Energy Resources Conservation Board and Alberta Public Utilities Board have been merged and has a new name called the Alberta Energy and Utilities Board. The new Board manages regulatory functions formerly undertaken by those two previous agencies.

The three utilities participate in the cost-pooling program of the Electric Energy Marketing Agency (EEMA). The EEMA was established in 1982 by the provincial government to help equalize power costs throughout Alberta. Under EEMA legislation, the utilities' generation and transmission costs are regulated by the Public Utilities Board. The Board also approves the selling prices of electricity to EEMA, which then pools the utilities' costs and resells the power at average prices back to the utilities. In the Fall of 1991, the provincial government established a panel to review the equalization policy. The panel released a report on the status of the EEMA in February 1993, recommending that transfer payments be provided only when costs exceed EEMA average by 6 per cent.

British Columbia

Electricity rate changes in the province of British Columbia require the approval of the British Columbia Utilities Commission (BCUC). Major generation and transmission projects require the approval of the provincial Cabinet. Upon receiving an application to construct a major facility, the government may refer the application to the BCUC for review and a recommended course of action. Projects that obtain Cabinet approval receive an Energy Project Certificate from the province.

Yukon

The Yukon Energy Corporation and the Yukon Electrical Company are regulated by the Yukon Utility Board, under the *Public Utilities Act of 1986*. Under this Act, the Corporation and Company must file applications for rate changes or facility construction with the Board, which reviews the applications and makes a decision.

Northwest Territories

The Northwest Territories Power Corporation and Northland Utilities Enterprises Limited are regulated by the *Northwest Utilities Act* of 1989. Under the Act, they must file an application with the N.W.T. Public Utilities Board in order to receive authority for rate changes or facility development. Upon receiving an application, the Board holds a public hearing and then reaches a decision, which is final.

Electricity Regulatory Agencies

Canada:

- National Energy Board
- Atomic Energy Control Board
- Canadian Environmental Assessment Agency

Provinces:

- Newfoundland Board of Commissioners of Public Utilities
- Nova Scotia Board of Commissioners of Public Utilities
- New Brunswick Board of Commissioners
- Quebec Legislative Assembly
- Ontario Energy Board (Rates)
- Ontario Joint Hearing Board (Generating & Transmission)
- Manitoba Public Utilities Board
- Saskatchewan Legislature
- Alberta Energy and Utilities Board
- Electrical Energy Marketing Agency (Prices)
- British Columbia Utilities Commission
- Yukon Utility Board
- Northwest Territories Public Utilities Board

Electricity and the Environment

Energy is the engine of economic growth. It is also a major source of pollution. The need to develop relatively inexpensive sources of energy as a basis for economic growth, and increasing public pressure to limit environmental damage, present a major challenge to governments and utilities. In Canada, the task of balancing energy requirements and environmental demands is being handled in a number of ways including environmental impact analyses, development and application of techniques to reduce emissions and long term shifts in the fuel mix used to generate power.

Most, if not all, energy generation and transmission projects have some impact on the environment. These range from chemicals contained in flue gases to the effect on plant and animal life when clearing a way for transmission lines. Not all of these impacts are necessarily harmful or permanent and some are even seen as beneficial. The most significant of these impacts are identified briefly as follows:

Impacts Attributable to Electricity Generation

Coal-Fired Generation

Roughly sixty per cent of the energy produced in coal combustion is in the form of waste heat emanating from either the stack or the cooling water. Flue gases include a number of chemicals including sulphur dioxide and nitrogen oxides (which are major components of acid precipitation), hydrocarbons (which combine with nitrogen oxides in the atmosphere to produce low-level ozone which - in high concentrations - can harm certain crops) and carbon dioxide which may contribute to higher global mean temperatures. Other by-products of coal combustion include contaminated solid wastes and process waters.

Oil-Fired Generation

Oil-fired generation is generally considered to be less harmful than coal-fired because sulphur is removed from the oil during the refining process. However, exhaust gases still contribute carbon monoxide, sulphur dioxide, nitrogen oxide, hydrocarbons and carbon dioxide to the atmosphere.

Natural Gas Fired Generation

Hydrogen sulphide is removed from natural gas before shipment so that the principal by-products of combustion are carbon dioxide and water.

Hydro-Electric Generation

Environmental impacts result from dam construction at the reservoir site as well as downstream. These include the effect on the local climate, vegetation, fish and wild life caused by the creation or expansion of a reservoir and the construction of a dam and generating station. Water levels and flows are affected above and below the dam as are the nutrient content and temperatures of water bodies. Some of these impacts could be positive, including the reduction of seasonal flooding and the creation of possible new wild life reserves.

Nuclear Generation

Unlike the combustion of fossil fuels, nuclear generation does not produce any significant amounts of gaseous emissions. Indeed, environment impact is one area where nuclear energy may have a significant advantage. Nevertheless, safety and the management of radioactive wastes pose a challenge to the nuclear industry, both technically and in terms of public acceptance.

Impacts Attributable to Electricity Transmission

Construction of Transmission Lines

Many of the effects caused by line construction are temporary, including the disruption of wild and aquatic life, as well as noise and air pollution. However, where vegetation is cleared to make a right of way, local soil erosion and increased sedimentation of water bodies can result.

Operation and Maintenance of Transmission Lines

Plant and wild life along the right of way can be affected by herbicide application and cut-backs of vegetation. Other underground installations (such as a pipeline) might also be damaged due to the operation of a ground electrode and studies are currently underway to determine whether the lines' extra low frequency electro-magnetic fields are a danger to health.

Other Possible Contaminants

Polychlorinated Biphenyls (PCBs).

Because of their excellent insulating and thermal properties, PCBs are used in electrical equipment insulating oils. Current evidence suggests that there is no positive link between work place exposure to PCBs (as such) and the likelihood of contracting cancer. However, when involved in transformer or capacitor fires, PCBs release highly toxic substances called polychlorinated dibenzofurans (PCDF).

Acid Rain

Acid rain or acid precipitation, is the term given to the rain, snow, sleet, hail, frost or dew which contain sulphuric and nitric acids. Such acids can come from the atmospheric conversion of sulphur and nitrogen oxide (SO_x and NO_x) emissions. Around the world, up to half of the sulphur in the air comes from natural sources such as rotting vegetation, plankton, and in some places, volcanoes.

However, the principal sources of sulphur oxide emissions in North America are coal-fired power generating stations and non-ferrous ore (i.e., nickel, copper, lead and zinc) smelters. Coal-fired generating stations are the main source of sulphur emissions in the U.S., whereas in Canada 60 per cent come from smelters. The main source of nitrogen oxide emissions in both countries are vehicle exhausts.

U.S. emissions exceed Canadian by a factor of 5 for sulphur oxide and 10 for nitrogen oxide, but both countries contribute to each others problems through long-range atmospheric transportation of airborne pollutants. It is estimated that 80-90 per cent of the acid rain affecting Canada is attributable pollutants originating in the U.S.

The Greenhouse Effect

Life is possible on earth because of the existence in the atmosphere of a number of important gases, including carbon dioxide (CO_2), nitrous oxide (N_2O),ozone (O_3) and methane (CH_4). These gases behave as an insulating blanket, absorbing much of the heat escaping from the earth's surface and thereby trapping warmth within the lower atmosphere. This "greenhouse effect" is a natural phenomenon without which the earth's surface would be 30 degrees celsius colder, and uninhabitable to most existing life forms.

The issue is the relatively rapid increase in the build up of these greenhouse gases primarily as a result of the burning of fossil fuels and

other industrial and agricultural processes, and the effect some scientists believe this will have on global temperatures and, ultimately, on the world's climate and ocean levels.

Burning of fossil fuels (coal, oil and natural gas) to produce energy releases carbon dioxide and nitrous oxide into the atmosphere and also contributes to increased levels of surface ozone.

The most significant of these greenhouse gases is carbon dioxide. Since 1860, atmospheric CO_2 concentrations have risen from 270-290 ppmv (parts per million by volume) to nearly 350 ppmv today. Projections of CO_2 trends are subject to large uncertainties, but many scientists believe that concentrations of this and other greenhouse gases could double by the middle of the next century.

Responses to Environmental Impact of Electricity Generation and Transmission

A number of measures have been implemented by governments and industry to monitor and reduce the environmental impacts of electricity generation and transmission. These include the employment of technologies, fuel mix changes, studies and the development and application of government policies, standards, codes of practice and regulations. The most important of these are identified briefly in this summary and in more detail in separate notes.

Technological Measures

These measures are often introduced in response to government regulations and standards. Many are designed to reduce sulphur and nitrous oxide emissions (major contributors to acid precipitation) and include a number of flue gas desulphurization technologies, circulating fluidized bed combustion, low nitrous oxide burners, coal blending and cleaning and co-generation.

Switch to Environmentally More Benign Fuels

Although all methods of generating energy have an impact on the environment, some are considered to be less harmful than others. A decline in the relative importance of thermal generation (by fossil fuels - coal, oil and natural gas) and an increase in that of hydro and nuclear will reduce the emission of atmospheric pollutants, even where fossil fuel plants have been fitted with emission controls. The experience in Canada is mixed: the relative importance of fossil fuels declined from 23 per cent in 1970 to 17 per cent in 1987 but as total electricity generation more than doubled over this same period, there was an actual growth in thermal generation (from 47 to 78 terawatt hours) over this same period with a real decline only being registered in the last few years. Again, although the actual amount of hydro-electric power generated doubled between 1970 and 1987, its relative importance declined from 77 per cent to 66 per cent, while that of nuclear rose from under 1 per cent to 17 per cent.

Studies

Methodologically sound studies can play a major role in establishing the existence and nature of environmental impacts and are therefore a necessary first stage in the response. A number of current studies focus on determining whether or not some link exists between extra low frequency electromagnetic fields and various forms of cancer. The most interesting of these studies include one financed by Ontario Hydro, Hydro-Québec and Electricité de France and another by the U.S.

Electric Power Research Institute. Other important areas of study focus on PCBs, acid rain and the so-called "Greenhouse Effect". Another interesting study entitled "Project 88: Harnessing Market Forces to Protect our Environment: Initiatives for the New President," was produced by a team of experts and sponsored by Senators Wirth (Democrat-Colorado) and Heinz (Republican-Pennsylvania). This study focuses on economic tools that might be used to solve environmental problems relating to energy, climate change, land use and resource management.

Setting Emission Targets

The most important of these is the federal government's agreement with seven provincial governments to set limits on sulphur oxide emissions, which should result in a 50 per cent reduction by 1994 when compared to a 1980 base. Canada is also a signatory of the 1979 Helsinki Protocol on Sulphur Dioxide thereby agreeing to reduce transboundary emissions by 30 per cent by 1993 when compared to a 1980 base.

Concern with the effects of acid rain and the fact that important constituents of it can be carried in the atmosphere for considerable distances, has led to the establishment of emission limits and the development of transboundary emission accords.

In March 1985, the Canadian government announced a comprehensive program involving working with provincial governments and industry to reduce sulphur oxide emissions by 50 per cent by 1994 when compared to a 1980 base. As control of such emissions lie principally within provincial jurisdiction, it was necessary for all seven provinces involved to enter into a federal-provincial agreement to give effect to the overall target. This was done in December 1987, when the last of the seven provinces, Nova Scotia, signed the agreement with the federal government.

The sulphur oxide emission reduction targets for 1994 are set out in Table 4.1.

Environmental Assessment Review Processes

As was pointed out earlier, electricity generation and transmission projects have some impacts on the environment. Governments, industry and other groups in society have recognized the need to assess and reduce these impacts. For their part, federal and provincial governments have established processes that are designed to reduce the environmental consequences of electrical generation and transmission.

Despite differences from one province to another in the nature of the environment and in the scale and type of project proposed, there are some similarities in the processes developed by the various provincial governments to ensure that the development of electricity generation and transmission projects does minimum damage to the environment.

In most provinces, the proponent (a person, company, provincial agency or Crown corporation) is responsible for conducting an environmental assessment of activities. A lead agency (often in the department responsible for the environment) is normally appointed to review this assessment on behalf of the provincial government.

In all 10 provinces, decision-making occurs in discrete steps. Small, routine projects with no significant impacts are first screened out and allowed to proceed with a minimum loss of time and expense. Projects that may adversely affect the environment are submitted for a more detailed (and sometimes more visible and structured) review. Such projects could be subject to public review by an independent board or panel.

The Environmental Impact Statement (EIS) is used in most provinces and by the federal government to assess projects that may have a major adverse environmental impact. The EIS format is similar in all jurisdictions and involves (i) a project description, (ii) an analysis of how the project will affect the environment, and (iii) a description of proposed measures to reduce environmental impacts. It is normally prepared by the project proponent and is reviewed by the lead and other government agencies or by a public review board or panel.

The EIS process usually involves some form of public review, but the degree of formality varies among provinces, from formal legal procedures to informal community meetings. At both the federal and provincial levels, the final decision-maker is usually an elected official or officials -- a Cabinet minister or the entire Cabinet. This is the same as in the power regulation processes stated in Chapter 3.

The processes in place in Canadian jurisdictions are outlined below. Some of this material is reviewed in more detail in a report prepared by the Canadian Council of Ministers of the Environment (CCME).[1] Since this 1985 report was completed, British Columbia, Saskatchewan, Manitoba, New Brunswick, Prince Edward Island, and Newfoundland have introduced major changes, and these are reflected in this chapter. In addition, an Environmental Assessment Act was passed in Nova Scotia in 1988 and was proclaimed in July 1989. Alberta's Environmental Protection and Enhancement Act was passed in the summer of 1992 and went into effect September 1, 1993.

[1] William J. Couch, Ph.D. (ed), *Environmental Assessment in Canada: 1985 Summary of Current Practice in Canada.* (Ottawa, Canadian Council of Resource and Environment Ministers, 1985, catalogue number EN 104-4/1985.)

Federal Process

The Federal Government's Environmental Assessment Review Process

In December 1973, Cabinet established the federal Environmental Assessment Review Process (EARP) to ensure that the environmental effects of all federal proposals are assessed early in the planning process. A federal proposal is one initiated by a federal agency, or one that involves federal funding, federal property, or affects an area of federal responsibility. Federal Crown corporations are not bound by the Cabinet decision, but they are invited to participate in the process.

Under EARP, federal departments are responsible for assessing their own proposals. They conduct an initial screening to determine whether a given proposal will have significant environmental effects. If no such effects are perceived, the project may go ahead with appropriate monitoring by the initiating department. The results of all such decisions are published in summary form.

If potentially significant environmental effects are perceived, a formal review process is undertaken by an Environmental Assessment Panel created by the Minister of the Environment. The Panel is assisted in its work by the Federal Environmental Assessment Review Office. The Panel normally requires that the sponsor of the proposal prepare an EIS. If the Minister of the Environment and the initiating minister concur, the scope of the Panel may be broadened to include general socioeconomic effects and the need for the project.

Public participation is an integral part of the assessment process. Any person or organization with an interest in the proposal is provided with an opportunity to appear before the Panel.

Once a Panel has completed its deliberations and evaluated all information on a proposal, it prepares a report containing its findings and recommendations. A Panel could recommend that a proposal not proceed, that it proceed as planned, or that it proceed subject to certain terms and conditions. The recommendations are submitted to the Minister of the Environment and the initiating minister, who must decide
(i) to whom the recommendations are directed, (ii) to what extent they should be incorporated into terms and conditions governing the project, and (iii) in what manner they are to be made public. In the event of a disagreement between the two ministers, the question may be submitted to Cabinet.

Following the publication of a green paper in 1987 that identified a number of possible changes to the EARP process[2], the Federal Environmental Assessment Review Office (FEARO) has carried out extensive consultations with the public, and federal departments and agencies. Bill C-78, introducing a new Canadian Environmental Assessment Act (CEAA), was tabled in the House of Commons on June 18, 1990, and was discussed but not concluded in the 1990 session. Bill C-78 was reintroduced as Bill C-13 in the House of Commons on May 29, 1991. The CEAA received Royal Assent in June 1993 and was proclaimed in February 1995. Four key regulations addressing implementing issues were pre-published in the Canada Gazette Part I in September 1993. They are:

- the Law List - a list of statutes that trigger a Federal environmental assessment;
- the Comprehensive Study List - a list of projects considered important enough to warrant a mandatory detailed study;
- the Inclusion List - a list of activities that require assessment; and
- the Exclusion List - a list of projects that are excluded from assessment.

Prior to the publication, the regulations were the subject of an extensive public consultation through the Regulatory Advisory Committee (RAC), established by FEARO in 1992. Industry representatives on the RAC included the Mining Association of Canada, the Canadian Association of Petroleum Producers, the Canadian Electrical Association, the Canadian Nuclear Association, the Canadian Pulp and Paper Association, and environmental groups as well as native groups.

Over a period of 16 months, the RAC attempted to reach consensus on the regulations. In the end, consensus was reached on some pro-visions but many remained highly contentious. The proclamation of CEAA is completed in February 1995. And the Federal Environmental Assessment Review Office has been replaced by the Canadian Environmental Assessment Agency.

Provincial Processes

British Columbia

The principal legal basis for British Columbia's energy project review process is the Utilities Commission Act, 1980. Major energy projects cannot proceed until the proponent has received approval by means of an Energy Project Certificate, a Ministers' Order, or a Certificate of Public Convenience and Necessity, all of which set out the terms and conditions under which the facility may be constructed and operated.

[2] Environment Canada, *Reforming Environmental Assessment: A Discussion Paper.* (Ottawa, Minister of Supply and Services Canada 1987, catalogue number EN 106-5/1987.)

In the Spring 1994 Session of the Legislature, the Government of British Columbia introduced the new Environmental Assessment Act. The Act established a single, comprehensive process for the identification of the potential effects of major projects and the evaluation of the means to prevent or mitigate adverse impacts. The process ensures that projects are constructed and operated in a manner designed to avoid or reduce environmental and other adverse impacts and provide economic and social benefits over the long term, thereby supporting sustainability.

This Act provides an open, accountable, effective and efficient process which involves the public throughout. This process will be consistent and fair in its application, thus providing certainty and balance for environmental interests, business interests and the public.

The Act is a logical successor to processes that are now used to assess certain major projects, superseding the current Mine Development Assessment Process, Energy Project Review Process and Major Project Review Process.

To administer the Act, an Environmental Assessment Office was established and is headed by an Executive Director who is responsible for overall administration of the environmental assessment process.

Alberta

Alberta's Environmental Impact Assessment (EIA) process was established by the Land Surface Conservation and Reclamation Act of 1973. Pursuant to Section 8 of the Act, the Minister of the Environment may require the proponent of a proposed development to prepare an EIA report if he or she believes it is in the public interest to do so. The purpose of an EIA is to provide information to the public and the government to enable early identification and resolution of significant adverse effects on the environment.

The Alberta EIA process is implemented in accordance with the Alberta EIA Guidelines and administered by the Alberta Department of Environment. Most major resource developments proposed in Alberta are subject to this requirement. Major thermal and hydro generation projects require an EIA, and proponents of smaller projects must submit the environmental information necessary for the required approvals. In preparing an EIA, the proponent must consult with the public and provide opportunities for the public to participate in the preparation and review of the EIA.

Energy projects require the approval of the Alberta Energy Resources Conservation Board (ERCB) and Alberta Environment. Consequently, Alberta Environment and the ERCB coordinate their respective information requirements and reviews of energy projects. EIAs on energy projects are filed with Alberta Environment and the ERCB as part of the application to the ERCB. The ERCB may require a public hearing to be held for a project. After the ERCB makes its decision, Alberta Environment issues detailed environmental permits and licenses.

Following three years of extensive public consultation, Alberta's Environmental Protection and Enhancement Act was passed and proclaimed on September 1, 1993. Highlights of the legislation and the new regulations include provisions to establish a legislated environmental impact assessment process, increase public consultation and participation, and allow more public access to information on proposed developments which may impact the environment.

Saskatchewan

The Environment Assessment Act of 1980 requires environmental impact assessments to be completed for major development projects. Exemptions may be granted by Cabinet only in cases of emergency.

The province's environmental impact assessment and review process is administered by the Saskatchewan Department of Environment and Resources Management (formerly Department of Environment and Public Safety), and projects may proceed only with the approval of the Minister. Proposals are screened by the department to determine whether the Act applies to a project and, if so, the nature and scope of the EIA. If it is determined that an EIA is not required, the project may proceed subject to all other statutory requirements.

Where an EIA is required, proponents are encouraged to undertake a public participation program as early as possible so that public comments and recommendations may be considered during the preparation of the Environmental Impact Statement (EIS). Further safeguards are built into the process, such as a minimum 30-day public review of the EIS and the power given to the Minister to require a public information meeting to be conducted and/or appoint a board of inquiry. The final decision to approve (with or without conditions) or to refuse the proposed development rests with the Minister. The government intends to reform the current environmental review process in the coming year.

Manitoba

The Manitoba Environment Act of 1988 replaces the former Clean Environment Act of 1968 and the Environmental Assessment and Review Process, adopted as provincial Cabinet policy in 1975.

The Act ensures that any person or organization undertaking a development specified in the regulations is required to file a Proposal with the Department of Environment at an early stage in the planning schedule. Other developments of environmental consequence are governed by regulations setting standards for environmental protection.

Developments are classified according to their potential environmental impact. Class 1 developments are any activities discharging pollutants. Class 2 developments are any activities with significant environmental impact caused by factors in addition to pollution, such as transportation and transmission facilities. Class 3 developments involve large-scale projects such as major hydroelectric developments.

Every submission for a development must be filed at a public registry. Once a proposal is filed, the Department of Environment is required to invite publicly written comments on the proposal. For more complex proposals, study guidelines are developed to assist proponents in preparing environmental assessments. Both the guidelines and the completed assessment are made available to the public for review.

Public meetings hosted by the proponent or public hearings by the Manitoba Clean Environment Commission, or both, may be held as part of the assessment and review process. The Commission's role is to provide advice and recommendations to the Minister and to develop and maintain public participation in environmental matters.

The final product of the process is an environmental license with terms and conditions specific to the proposal. Alternatively, a license to proceed could be refused on the grounds of unacceptable environmental damage.

Ontario

The Minister of the Environment is responsible for the administration of the Environmental Assessment Act, which promotes improved planning by involving government ministries and agencies and the public in the

environmental assessment, planning and approval process. (The environmental process in Ontario is also subject to the terms of the Consolidated Hearings Act, 1981. Details of the Consolidated Hearings Act may be obtained from *Environmental Assessment in Canada*[3], or from the October 1987 issue of *Canadian Environmental Law Reports.*[4] The environmental assessment process in Ontario is currently being reviewed by the government. Amendments to the Environmental Assessment Act are expected to be proposed in the very near future.

The Environment Minister may, with the approval of Cabinet, exempt proponents from the application of the Environmental Assessment Act, which currently applies to the activities of provincial ministries, municipalities and conservation authorities. Only those projects of the private sector designated by regulation are subject to the Act. Proponents planning a project must determine if the Act applies; where it does not apply; or where an exemption has been granted, the activity may proceed. If the Act applies, the proponent must prepare an Environmental Assessment (EA), which is reviewed by the Ministry of Environment and other interested provincial and federal government organizations.

The Ministry subsequently prepares a Government Review which, together with the EA, is released for a minimum 30-day public review. A hearing of the Environmental Assessment Board may then be requested by the reviewers, the public or the proponent. The Minister -- with the concurrence of Cabinet -- will make a decision whether to accept the EA, and whether to approve the undertaking, with or without conditions. The Minister may refer the decision to accept the EA, or the decision to approve the undertaking, or both, to a Board hearing. When the Minister decides to refer the matter to a Board hearing, the Board must give reasonable notice of the hearing, which is open to the public. The Minister or Cabinet has 28 days to make any amendments to the Board's decision; if no amendments are made within this period, the Board's decision becomes binding.

Quebec

In Quebec, the process of environmental assessment varies depending on whether a project is in the south of the province or in a territory that is the subject of agreements with native people.

The 1972 Environment Quality Act was amended significantly in 1978 to include an environmental impact assessment and review procedure. By regulation, this procedure applies essentially to projects in the south of the province. When a project is subject to the procedure, the proponent must submit an EIA to the Department of the Environment for an admissibility analysis and an evaluation of the environmental acceptability of the project. All projects are subject to a public consultation period, during which any citizen may ask the Minister of the Environment to hold a public hearing. Citizens can thus voice their views before the project is referred to Cabinet for acceptance or refusal. A new Act modifying the environmental evaluation process was passed in 1992. It will come into effect as soon as the government adopts secondary legislation.

In the northern Quebec territories, the provincial government has implemented two procedures to assess and review the environmental and social impacts of a given project. The first procedure is applicable to the James Bay region (between the 49th and 55th parallels). A feature of this procedure is the use of committees on which native people are always represented. These committees advise the Minister of the Environment throughout the various stages of the authorization process. North of the 55th parallel, the Kativik Environmental Quality Commission is in charge of reviewing the impact assessment study and

[3] William J. Couch, Ph.D., op. cit.
[4] *Canadian Environmental Law Reports*, New Series, Vol. 1, Part 6, October 1987.

has decision-making authority. These procedures, which were incorporated into the Environment Quality Act, stemmed from the James Bay and Northern Quebec Agreement (1975) and the Northeastern Quebec Agreement (1978).

New Brunswick

New Brunswick's Regulation on Environmental Impact Assessment came into effect in July 1987, to provide a legislative framework for environmental planning, including opportunities for public involvement. The Regulation, which replaced the province's 1975 Policy on Environmental Assessment, is designed to identify the environmental impacts associated with development proposals, before their implementation.

Under the Regulation, individuals, companies or public agencies proposing certain types of projects (for example, all electric power generating facilities with a production rating of three MW or more, and all electric power transmission lines exceeding sixty-nine kV in capacity or five km in length) are required to register information about the project with the Minister of Environment, at an early stage in the planning cycle. The Minister then screens the proposal to determine whether it is likely to have significant environmental impacts, including socioeconomic and biophysical effects.

If it appears that the project's impacts are likely to be significant, the Minister will inform the proponent that an EIA is required, and staff from the Department of Environment will work with the proponent in preparing initial draft guidelines for the EIA Study. A Review Committee, consisting of technical specialists from government agencies potentially affected by the proposal, is appointed by the Minister to formulate draft guidelines for the Study. These draft guidelines, which identify the important environmental issues to be addressed, must then be issued by the Minister for public comment, and any interested party may provide written comments to the Minister.

The principal objective of the EIA Study is to predict the project's impacts, should it proceed. Information gathered during the study is compiled in a draft Environmental Impact Assessment Report, which is then carefully examined by the Review Committee. If, on the advice of the Committee, the Minister is satisfied that the report adequately addresses all aspects of the guidelines, a second and more comprehensive opportunity for public involvement begins. A summary of the report, comments of the Review Committee, and full copies of the final report are released for public review and comment.

A public meeting to discuss the EIA takes place. Thereafter, the Minister reviews the study and public comments, and then recommends to the Lieutenant-Governor in Council whether or not the project should proceed.

A proposal to revise the current environmental impact assessment regulation has been prepared by the Department of Environment and has received comments for input from other government departments and the public. A new clean air Act is likely to be recommended to the New Brunswick Legislature in the fall of 1996.

Nova Scotia

The current legal basis for environmental impact assessment in Nova Scotia is the Environmental Assessment Act. The Nova Scotia Department of the Environment (NSDOE), in consultation with other government agencies, is responsible for screening all projects submitted and advising the Minister on those that may have a significant and adverse environmental impact. After reviewing NSDOE's advice, as well as any public concern expressed, the Minister decides whether a project requires an

Environmental Assessment (EA) Report. Where it is decided one is required, the proponent prepares a draft Report in response to guidelines and submits it to NSDOE. The department, other interested provincial and federal agencies, and the public, review the EA Report. NSDOE then recommends to the Minister whether the project should be approved, with or without conditions, or refused.

The public is invited to participate in the review process by providing comments when a project is submitted to the NSDOE, when study guidelines are issued, and when the EA Report is released. The Minister, taking into consideration NSDOE's recommendations and the views of the public, decides whether the project should proceed and, if so, under what conditions.

The Department of Environment is now undertaking comprehensive legislative review and consolidation of all environmental acts (14) and regulations (44). A proposed new Nova Scotia Environment Act was released for public consultation in October 1993, and a report on the results of public consultation was published in June 1994. This new Act was passed by the Legislature and was proclaimed in January 1995.

Prince Edward Island

The Environmental Protection Act of 1988 provides the overall legal authority for the environmental assessment process. It requires that any person who wishes to initiate a project must file a written proposal with the Department of Environmental Resources (formerly Department of Environment) and obtain written approval from the Minister to proceed.

With respect to utilities, the process is set out in the Electric Power and Telephone Act, which authorizes the Public Utilities Commission to issue project-specific guidelines to the proponent for the preparation of an EIS, if it believes that the project may adversely affect the environment. A copy of the EIS is then sent by the Commission to the Executive Council for its consideration. The Council may make a decision on the evidence available, or it may determine that the public interest requires public hearings to be held in the locality affected by the project. After the public hearings, the Commission examines the evidence and issues its findings to the Executive Council.

Newfoundland

The province's environmental assessment process operates under the authority of the Environmental Assessment Act of 1980, which is administered by the Department of Environment and Lands.

Any project that may have a significant adverse environmental impact must be registered with the Minister of Environment and Lands. After public and interdepartmental reviews of the registration document, the Minister, on the advice of the department, decides whether or not an EIS is required. If an EIS is not required, the project may proceed subject to other relevant acts or regulations.

Where the Minister, on the advice of the Department, decides that an EIS may be required, an Environmental Preview Report (EPR) can be ordered. The EPR is prepared by the proponent and is available for public review and comment. Upon examination of the EPR, the Minister decides whether an EIS is required. If one is not required, the project may proceed subject to other relevant acts or regulations.

Where an EIS is required, it is prepared by the proponent; the Minister then makes it available for public review and comment. Should strong public interest be expressed, the Minister may recommend to Cabinet that an Environmental Assessment Board be appointed to conduct

public hearings. The Minister makes the Board's report public, delivers copies to Cabinet, and subsequently recommends to Cabinet whether the project should be permitted to proceed, with or without conditions, or whether permission should be refused.

Like some of the other provinces, the Government of Newfoundland is now carrying out an internal study on its environmental review process. The government intends to modify or change the existing acts or regulations during the coming year.

Table 4.1 is on the following page.

Tables & Figures

Table 4.1
Sulphur Oxide Emission Reduction Targets, 1994

Province	Base Case (tonnes)	Reductions (tonnes)	% Objectives	Emissions (tonnes)
Manitoba	738 000	188 000	25.5	550 000
Ontario	2 194 000	1 529 000	69.7	665 000
Quebec	1 085 000	485 000	44.7	600 000
New Brunswick	215 000	30 000	14.0	185 000
P.E.I.	6 000	1 000	16.7	5 000
Nova Scotia	219 000	15 000	6.8	204 000
Newfoundland	59 000	14 000	23.7	45 000
Total	4 516 000	2 262 000	50.0	2 254 000

Source: Natural Resources Canada

Electricity Consumption

Electricity and Primary and Secondary Energy

Electricity constitutes a significant market share of Canada's primary and secondary energy consumption. The contribution of electricity to total primary energy consumption[1] has steadily increased from 14 per cent in 1960 to 34 per cent in 1994, as shown in Figure 5.1. In terms of volume, primary energy consumption delivered in the form of electricity increased from 463 PJ in 1960 to 3350 PJ in 1994, an average annual growth of 5.9 per cent. This is more than double the average annual growth of non-electric primary energy consumption of 2.5 per cent registered for the same period. (Since 1990, the International Energy Agency (IEA) has agreed that hydro should be converted at 3.6 rather than 10.8 megajoules per kilowatt hour for the primary energy form).

Electricity constitutes a much smaller market share of secondary energy consumption[1] than primary energy consumption because of losses. Figure 5.2 indicates that electricity's share of Canadian secondary energy consumption was 11 per cent in 1960, and 25 per cent in 1994. The consumption growth rate for electricity was estimated to be 4.5 per cent during the period 1960-94, compared with non-electric secondary energy consumption of 2.3 per cent.

Total Electricity Consumption

In planning an electrical system, total electricity consumption (demand) must be determined first, followed by what type of energy and capacity mix is required to meet this demand.

[1] *For definition, please see appendix on* ***Definitions and Abbreviations.***

Total electricity consumption in a given country, region, or area normally includes generation by electric utilities, generation by industrial establishments, and net imports (imports minus exports).

Canada's total electricity consumption has experienced two distinct periods over the past 34 years: the first period was one of high growth from 1960 to 1974, followed by a period of low growth from 1975 to 1994. The abrupt change coincided with the first oil crisis of 1973-74, following which consumption growth rates in the ten provinces and two territories shrunk significantly. This dramatic reduction in electricity consumption growth was mainly attributed to reduced economic growth, high energy prices and energy conservation efforts. As indicated in Table 5.1, average annual growth rate of Canadian electricity consumption during the period 1960-74 was 6.6 per cent, compared with only 3.3 per cent for the period 1975-94.

In 1994, Canadian electricity consumption rose by only 1.3 per cent due to slow economic growth. The real Gross Domestic Product grew 4.6 per cent as the economy recovered from a recession which began in 1990. Energy conservation resulting from the implementation of demand-side management and relative warm weather were the major factors contributing to low domestic electricity consumption.

Ontario is the only province that has experienced consecutive negative electricity demand growth since 1990. This occurred largely because of the economic recession, mild weather, energy conservation efforts in the province, and rate increases.

Although its market share has been declining, the industrial sector is still the major user of electricity in Canada. Of the total electricity consumed in 1994, it is estimated that about 42 per cent was consumed in the industrial sector, 28 per cent in the residential sector,

23 per cent in the commercial sector, and 7 per cent in transmission and distribution losses.

Since 1960, commercial sector energy consumption growth has been remarkable, averaging 6.9 per cent annually, compared with 5.9 per cent for the residential sector, and only 3.4 per cent for the industrial sector. Transmission and distribution losses have been reduced steadily since 1960 partly due to improvements of transmission technology.

Table 5.3 shows electricity flows in Canada. Quebec was the largest producing and consuming province, accounting for 31 per cent of Canada's total production and about 35 per cent of total consumption. Ontario was second with 28 per cent of production share and also 28 per cent of consumption share. British Columbia was in the third place, with 11 per cent in production and 12 per cent in consumption shares.

Per Capita Electricity Consumption

As in the case of total consumption, per capita electricity consumption in Canada exhibited high and low growth patterns before and after the oil crisis of 1973-74. For the period 1960-94, Saskatchewan had the highest annual per capita growth in electricity consumption, averaging 6.6 per cent, followed by Prince Edward Island with 6.3 per cent, and Alberta with 5.8 per cent. High per capita electricity consumption in Saskatchewan was due to a slow population growth. During the past 34 years, Saskatchewan's growth rate was 0.3 per cent compared to the national average of 1.5%. In fact, Saskatchewan's population has been declining since 1988.

In 1994, Quebec was the largest electricity user in Canada with 23 647 kWh per person, about 41 per cent higher than the national average. This high electricity use is attributed to relatively low electricity prices and a high percentage of households (about 71 per cent) using electricity for space heating. In comparison, Prince Edward Island was the smallest electricity user in Canada with 6044 kWh (only about 36 per cent of the national average). Prince Edward Island has the highest electricity prices of the ten provinces and does not use electricity for household space heating. A great majority of households in Prince Edward Island use oil for space heating.

Household Characteristics and Facilities

As was pointed out earlier, electricity consumption in the residential sector has steadily increased, from a 19 per cent market share in 1960 to 28 per cent in 1994. In addition to economic factors, changes in household characteristics and household facilities and equipment also have considerable impact on residential electricity consumption. Table 5.5 summarizes household characteristics and facilities by province for 1994..

During the past 19 years, the number of households in Canada has increased from 6.9 million in 1976 to 10.4 million in 1994, a net increase of 3.5 million. However, the average number of persons per household has declined from 3.15 to 2.62 over the same period.

The use of electricity for space heating, mainly in the provinces of Quebec and New Brunswick, has steadily increased from 13 per cent of total households in 1976 to 33 per cent by 1994; the number of air conditioners from 13 per cent to 27 per cent; and automatic dishwashers from 19 per cent to 46 per cent. The use of electric washing machines also increased slightly over the same period, from

76 per cent to 79 per cent, while the use of electric clothes dryers increased significantly from 51 per cent to 75 per cent. By the end of 1994, households equipped with refrigerators and colour TV sets in Canada reached 99 and 98 per cent respectively.

Economic Growth and Electricity Consumption

Electricity consumption is affected by many factors: economic activity, demographic variables, electricity prices, other energy prices, conservation, policy changes, technological changes and weather. However, aggregate economic activity [as measured by the Gross Domestic Product (GDP)] is the most important variable. The historical relationship between per capita GDP and per capita electricity consumption is shown in Figure 5.4. Although the historical relationship between national economic growth and electricity consumption was dislocated between 1979 and 1983 (because of the second oil crisis of 1979 and the 1982 recession - the worst recession since WW II), it has reappeared since 1984.

Peak Demand

Peak demand is the annual maximum average kilowatt load of one hour duration within an electrical system. All electrical systems in Canada are peak in the winter. Table 5.8 reports the day in the winter which had the highest one-hour demand for each province over the 1993-94 period. For Canada as a whole, peak demand grew from 17 264 MW in 1960 to 90 167 MW in 1994 (Table 5.6), an average annual growth rate of 5.0 per cent. In comparison, total electricity consumption during the same period grew at an average of 4.5 per cent.

In 1994, peak demand increased by 4.8 per cent, which was mainly attributed to the strong growth in Quebec and Ontario. (Prior to 1987, *Electric Power in Canada* reported peak demand for the calendar year. However, beginning in 1987, calendar-year peak was replaced by winter peak - November to February. This change was made in order to make our reporting period consistent with that of the utilities.)

Load Factor

Load factor is defined as the ratio of average demand to peak demand in any given period. More precisely, it is the energy demand in kilowatt hours divided by the product of the number of hours in the period, multiplied by the peak demand in kilowatt. (In a year-base, average demand equals annual energy consumption divided by 8760 hours per year.)

Table 5.7 shows that for the electric power industry in Canada as a whole, load factor has declined since 1960. This has occurred because peak demand has grown faster than energy demand (5.0 per cent compared with 4.5 per cent). In 1960, the industry load factor was 72.3 per cent, but by 1980 it had gradually reduced to 65.6 per cent. Since then, the load factor have further reduced to 62.2 per cent.

Labour Productivity of Canada's Electric Utilities

To measure Canada's electric utility corporate performance, one of the best indicators is labour productivity, which is defined as total energy delivered per regular employee. Regular employees include full-time employees

considered permanent and involved in electrical utility service.

As Table 5.9 indicates, labour productivity including exports has increased from 3.41 GWh per person in 1970 to 6.04 GWh per person in 1993, with an average annual growth rate of 2.5 per cent. If exports are excluded, the adjusted average annual growth rate is 2.3 per cent.

Labour productivity improved about 7.9 per cent (including exports) and 6.8 per cent (excluding exports) in 1993 as a result of increased energy deliveries of 3.0 per cent, accompanied by a 4.4 per cent reduction in regular employees.

Tables and figures referred to in this chapter are on the following pages.

Tables & Figures

Table 5.1
Electricity Consumption by Province

	Electricity Consumption (GWh)					Average Annual Growth Rate (per cent)			
	1960	1970	1980	1990	1994*	1960-74	1975-94	1960-94	1993-94
Nfld.	1 427	4 770	8 545	10 422	10 959	11.5	3.0	6.2	0.5
P.E.I.	79	250	518	753	816	11.9	3.5	7.1	1.2
N.S.	1 733	3 706	6 814	9 678	9 974	8.7	3.0	5.3	0.6
N.B.	1 684	4 221	8 838	13 173	14 205	10.1	4.0	6.5	2.4
Que.	44 002	69 730	118 254	157 308	172 172	5.4	3.5	4.1	1.2
Ont.	37 157	69 488	106 509	142 818	137 430	6.4	2.3	3.9	-0.2
Man.	4 021	8 601	13 927	17 450	18 901	7.9	2.5	4.7	1.4
Sask.	2 124	5 402	9 827	13 589	15 926	9.2	4.3	6.1	4.2
Alta.	3 472	9 880	23 172	42 041	50 195	10.7	6.5	8.2	6.3
B.C.	13 413	25 761	42 789	57 206	59 310	6.9	3.2	4.5	0.7
Yukon	89	220	381	485	297	9.3	-0.9	3.6	-11.3
N.W.T.	100	308	494	472	591	10.2	1.8	5.4	0.5
Canada	**109 304**	**202 337**	**340 068**	**465 395**	**490 776**	**6.6**	**3.3**	**4.5**	**1.3**

* Preliminary Data

Source: Electric Power Statistics, Volume II, Statistics Canada, catalogue 57-202

Table 5.2
Electricity Consumption in Canada by Sector

	Electricity Consumption (GWh)						Average Annual Growth Rate (per cent)	
	1960	1970	1980	1990	1993	1994*	1960-94	1993-94
Residential	20 397	43 431	92 440	137 001	138 023	139 871	5.8	1.3
	(19)	(21)	(27)	(29)	(29)	(28)		
Commercial	12 632	44 068	75 912	110 057	113 324	113 860	6.9	0.5
	(12)	(22)	(21)	(24)	(23)	(23)		
Industrial	66 353	98 450	142 247	184 136	201 949	204 654	3.4	1.3
	(60)	(49)	(42)	(40)	(42)	(42)		
Line losses**	9 920	16 388	32 469	34 201	30 995	32 391	3.5	4.5
	(9)	(8)	(10)	(7)	(6)	(7)		
Total	109 304	202 337	340 068	465 395	484 291	490 776	4.5	1.3
	(100)	(100)	(100)	(100)	(100)	(100)		

* Preliminary data.
** Losses during transmission, distribution and unallocated energy.
Figures in parentheses are percentage shares.

Source: Electric Power Statistics, Volume II, Statistics Canada, catalogue 57-202 and Natural Resources Canada

Table 5.3
Provincial Electricity Consumption and Generation, 1994

	Generation	Exports to Provinces	Exports to U.S.A.*	Imports from Provinces	Imports from U.S.A.	Consumption
	(GWh)					
Nfld.	38 405	27 446	0	0	0	10 959
P.E.I.	40	0	0	776	0	816
N.S.	9 760	46	0	260	0	9 974
N.B.	15 867	1 684	2 340	2 220	142	14 205
Que.	162 899	3 591	17 337	28 897	1 304	172 172
Ont.	148 433	858	13 373	1 841	1 387	137 430
Man.	28 435	1 914	8 666	1 004	42	18 901
Sask.	15 471	1 125	63	1 515	128	15 926
Alta.	52 295	2 587	0	484	3	50 195
B.C.	61 015	307	9 233	2 561	5 274	59 310
Yukon	297	0	0	0	0	297
N.W.T.	591	0	0	0	0	591
Canada	**533 508**	**39 558**	**51 012**	**39 558**	**8 280**	**490 776**

* Service exchange is included.

Source: Natural Resources Canada

Table 5.4
Per Capita Electricity Consumption by Province

	Per Capita Consumption (kWh/person)						Average Annual Growth Rate (per cent)	
	1960	1970	1980	1990	1993	1994	1960-94	1993-94
Nfld.	3 184	9 226	14 758	18 188	18 671	18 830	5.4	0.9
P.E.I.	765	2 273	4 177	5 748	6 060	6 044	6.3	0.0
N.S.	2 385	4 739	7 988	10 813	10 654	10 422	4.4	-2.2
N.B.	2 864	6 732	14 850	18 245	18 351	18 715	5.7	2.0
Que.	8 565	11 597	18 735	23 556	23 537	23 647	3.0	0.5
Ont.	6 086	9 203	12 422	14 648	12 727	12 576	2.2	-1.2
Man.	4 932	8 750	13 521	16 024	16 556	16 712	3.7	0.9
Sask.	1 750	5 741	10 131	13 630	15 098	15 522	6.6	2.8
Alta.	2 695	6 194	11 135	17 000	17 574	18 413	5.8	4.8
B.C.	8 386	12 124	16 220	18 259	16 483	16 170	2.0	-1.0
Yukon	4 589	11 957	17 085	18 654	10 807	9 900	2.3	-8.4
N.W.T.	5 304	8 851	11 052	8 741	9 333	9 234	1.6	-1.1
Canada	**6 184**	**9 501**	**13 112**	**17 490**	**16 734**	**16 780**	**3.0**	**0.3**

Source: National Resources Canada

Table 5.5
Household Characteristics and Facilities in Canada, 1994

	Canada	Nfld	P.E.I.	N.S.	N.B.	Que.	Ont.	Man	Sask.	Alta	B.C.
Total number of households(1000)	10 387	183	48	332	255	2 720	3 820	397	361	928	1 344
Average persons per household	2.6	3.1	2.7	2.7	2.8	2.5	2.7	2.6	2.6	2.7	2.5
Single dwellings* (%)	67	87	81	73	79	53	71	76	81	74	68
Electricity for space heating (%)	33	45	-	22	58	71	18	29	4	-	27
Air conditioners (%)	27	-	-	5	8	15	48	48	32	8	9
Electricity for cooking (%)	94	97	83	90	96	98	92	99	97	91	93
Microwave ovens (%)	82	77	79	83	84	79	82	81	85	87	81
Refrigerators (%)	99	100	100	100	99	99	99	100	100	99	100
Freezers (%)	59	79	67	65	73	48	58	72	81	69	59
Automatic dishwashers (%)	46	23	31	33	37	47	44	43	49	58	53
Electric washing machines (%)	79	92	83	81	88	85	74	77	86	81	75
Electric clothes dryers (%)	75	80	77	74	85	80	70	74	84	79	73
Colour TV sets (%)	98	97	98	99	98	98	98	97	99	98	98

* Including mobile homes.

Source: Household Facilities and Equipment, 1994, Statistics Canada, catalogue 64-202

Table 5.6
Peak Demand by Province

	Peak Demand (MW)						Average Annual Growth Rate (per cent)	
	1960	1970	1980	1990	1993	1994	1960-94	1993-94
Nfld.	245	763	1 538	1 848	1 907	1 820	6.1	-4.6
P.E.I.	21	55	104	135	143	148	5.9	3.5
N.S.	356	814	1 197	1 825	1 922	1 731	4.8	-9.9
N.B..	319	726	1 699	2 627	2 836	2 853	6.7	0.6
Que.	5 871	11 127	20 680	29 259	30 932	33 755	5.3	9.1
Ont.	6 391	12 048	17 767	23 752	25 246	26 718	4.3	5.8
Man.	772	1 565	2 681	3 524	3 564	3 268	4.3	-8.3
Sask.	418	1 028	2 085	2 356	2 482	2 525	5.4	1.7
Alta.	714	1 894	3 879	6 509	6 874	6 965	6.9	1.3
B.C.	2 123	4 492	7 384	9 329	9 988	10 227	4.7	2.4
Yukon	19	39	75	81	57	62	3.5	8.8
N.W.T.	15	41	81	107	89	95	5.6	6.7
Canada	17 264	34 592	59 170	81 352	86 040	90 167	5.0	4.8

* Preliminary Data

Source: Electric Power Statistics, Volume I, Statistics Canada, catalogue 57-204

Table 5.7
Load Factor by Province

	1960	1965	1970	1975	1980	1985	1990	1993	1994
					(per cent)				
Nfld.	66.5	72.6	71.4	68.7	65.3	64.5	64.4	65.3	68.7
P.E.I.	66.4	65.4	65.8	65.4	68.4	64.9	63.7	64.3	62.9
N.S.	59.5	66.4	62.7	58.4	59.3	62.0	60.5	58.9	65.8
N.B.	58.0	60.3	60.0	62.2	53.8	62.5	57.2	55.8	56.8
Que.	85.6	72.5	71.5	67.9	65.3	64.5	61.4	62.8	58.2
Ont.	66.4	65.4	65.8	65.4	68.4	64.9	68.6	62.2	58.7
Man.	59.5	66.4	62.7	58.4	59.3	62.0	56.5	60.0	66.0
Sask.	58.0	60.3	60.0	62.2	53.8	62.5	65.8	70.2	72.0
Alta.	55.5	57.1	59.6	64.2	68.2	72.3	73.7	78.0	82.2
B.C.	72.1	71.6	65.5	64.4	66.2	66.1	70.0	67.1	66.2
Yukon	53.5	77.8	64.4	60.9	58.0	54.3	68.4	67.1	54.7
N.W.T.	76.1	58.6	85.8	71.3	69.6	70.6	50.4	74.9	71.0
Canada	72.3	68.1	66.8	65.7	65.6	65.1	65.3	64.4	62.2

Source: Calculated from Tables 5.1 and 5.6

Table 5.8
Days of Peak Demand, Winter 1994-95

Province	Day
Newfoundland - Labrador	January 6
Newfoundland - Island	February 13
Prince Edward Island	December 20
Nova Scotia	January 11
New Brunswick	January 11
Quebec	February 6
Ontario	February 6
Manitoba	January 9
Saskatchewan	January 3
Alberta	December 5
British Columbia	December 5
Yukon	January 6
Northwest Territories	January10

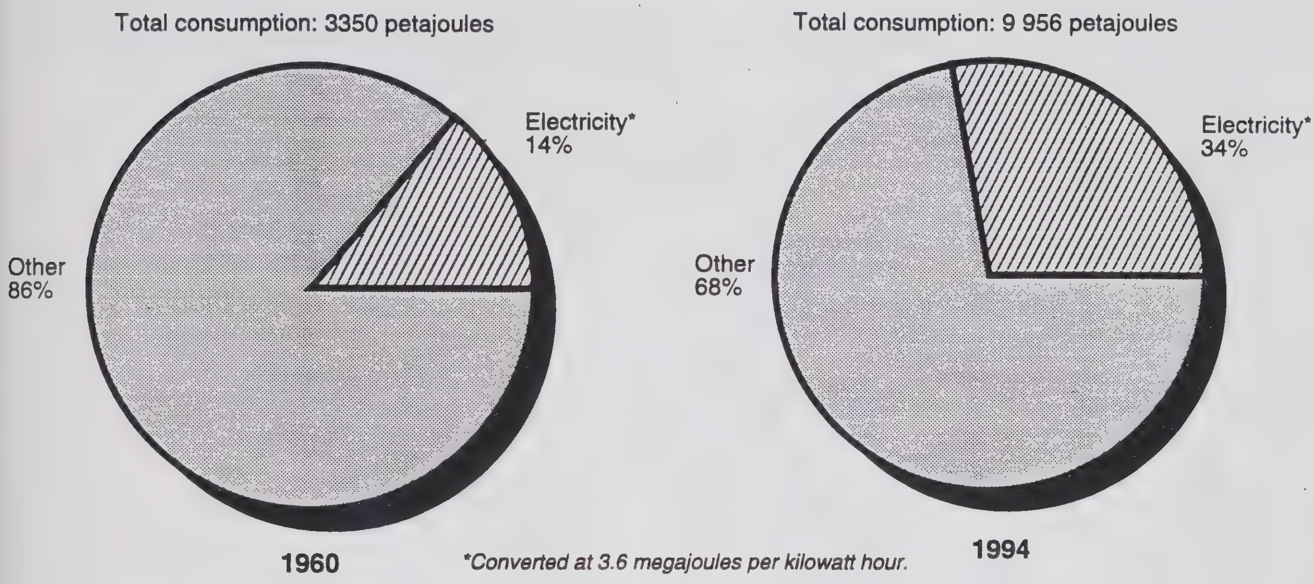
Source: Statistics Canada

Table 5.9
Labour Productivity of Canada's Electric Utilities

Year	Energy delivered including exports (GWh)	Domestic energy delivered (GWh)	Average regular employees	Labour productivity including exports (GWh/person)	Labour productivity excluding exports (GWh/person)
1970	148 526	145 114	43 597	3.41	3.33
1975	208 422	203 335	55 855	3.73	3.64
1980	292 822	264 972	65 504	4.47	4.05
1985	367 053	327 059	64 365	5.70	5.08
1986	381 292	344 681	64 483	5.91	5.35
1987	402 241	361 846	65 373	6.15	5.54
1988	408 585	381 262	66 226	6.17	5.76
1989	407 245	389 448	67 736	6.01	5.75
1990	401 188	386 234	70 988	5.65	5.44
1991	415 314	393 543	74 001	5.61	5.32
1992	421 383	396 395	75 219	5.60	5.27
1993	434 188	405 125	71 906	6.04	5.63

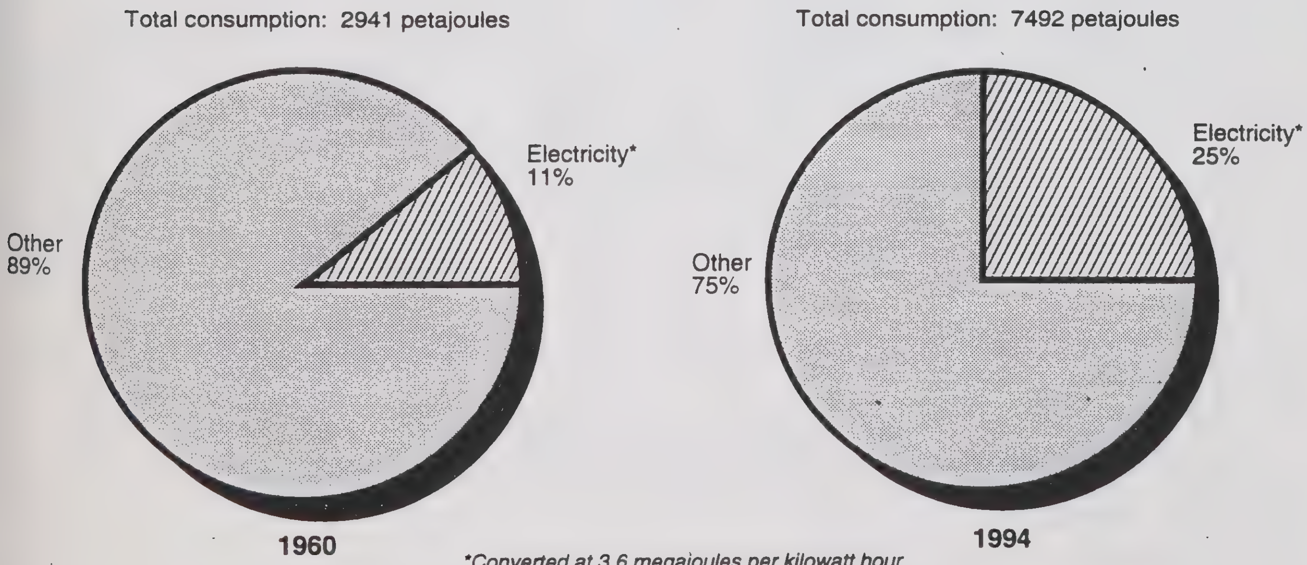
Source: 1993 Canadian Utility Composite Performance and Productivity Results, Canadian Electrical Association, June 1994, p. 29

Figure 5.1 Primary Energy Consumption in Canada



Converted at 3.6 megajoules per kilowatt hour.

Figure 5.2 Secondary Energy Consumption in Canada



Converted at 3.6 megajoules per kilowatt hour.

Figure 5.3
Electricity Generation, Consumption and Net Transfers, 1994 (GWh)

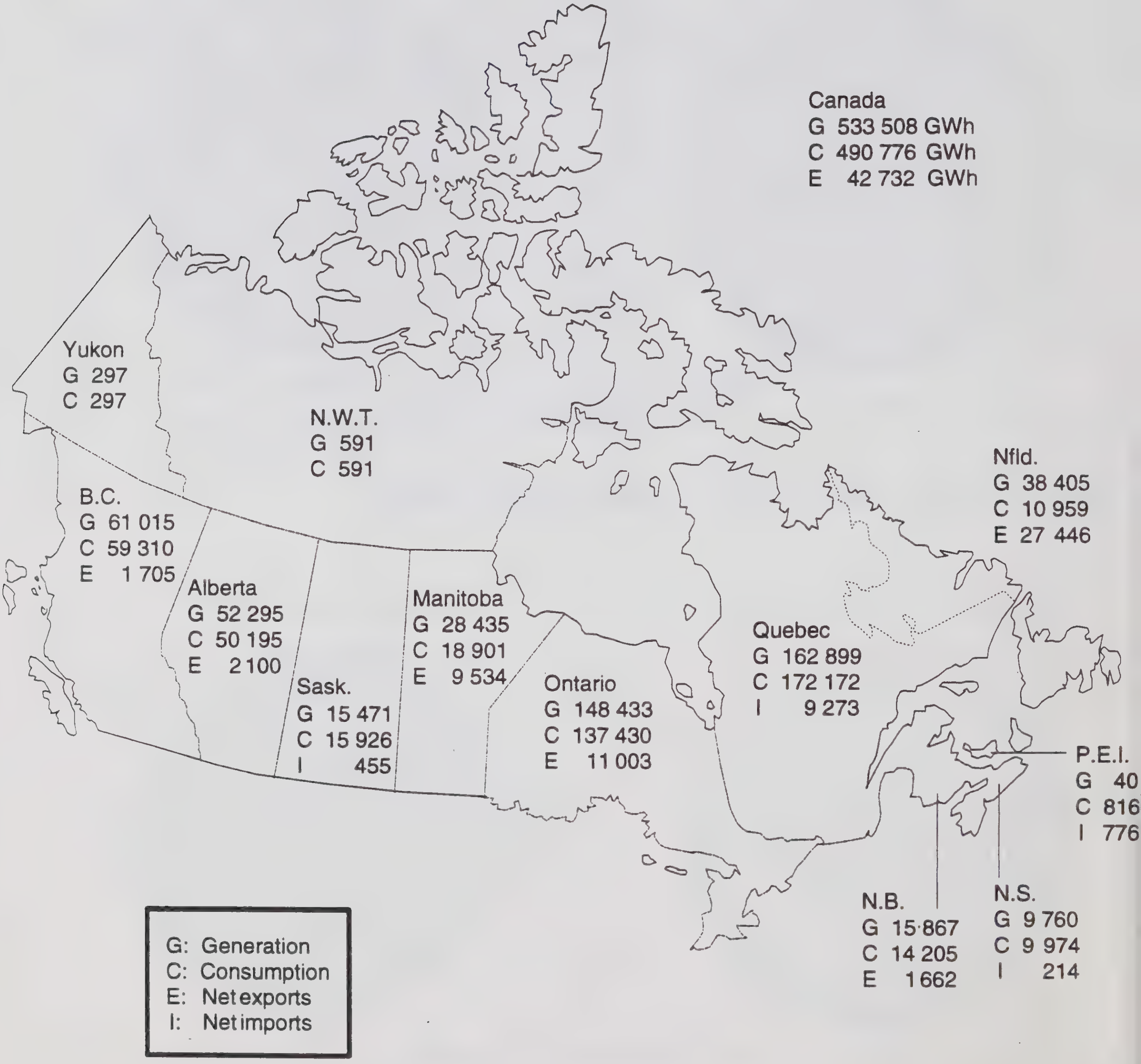
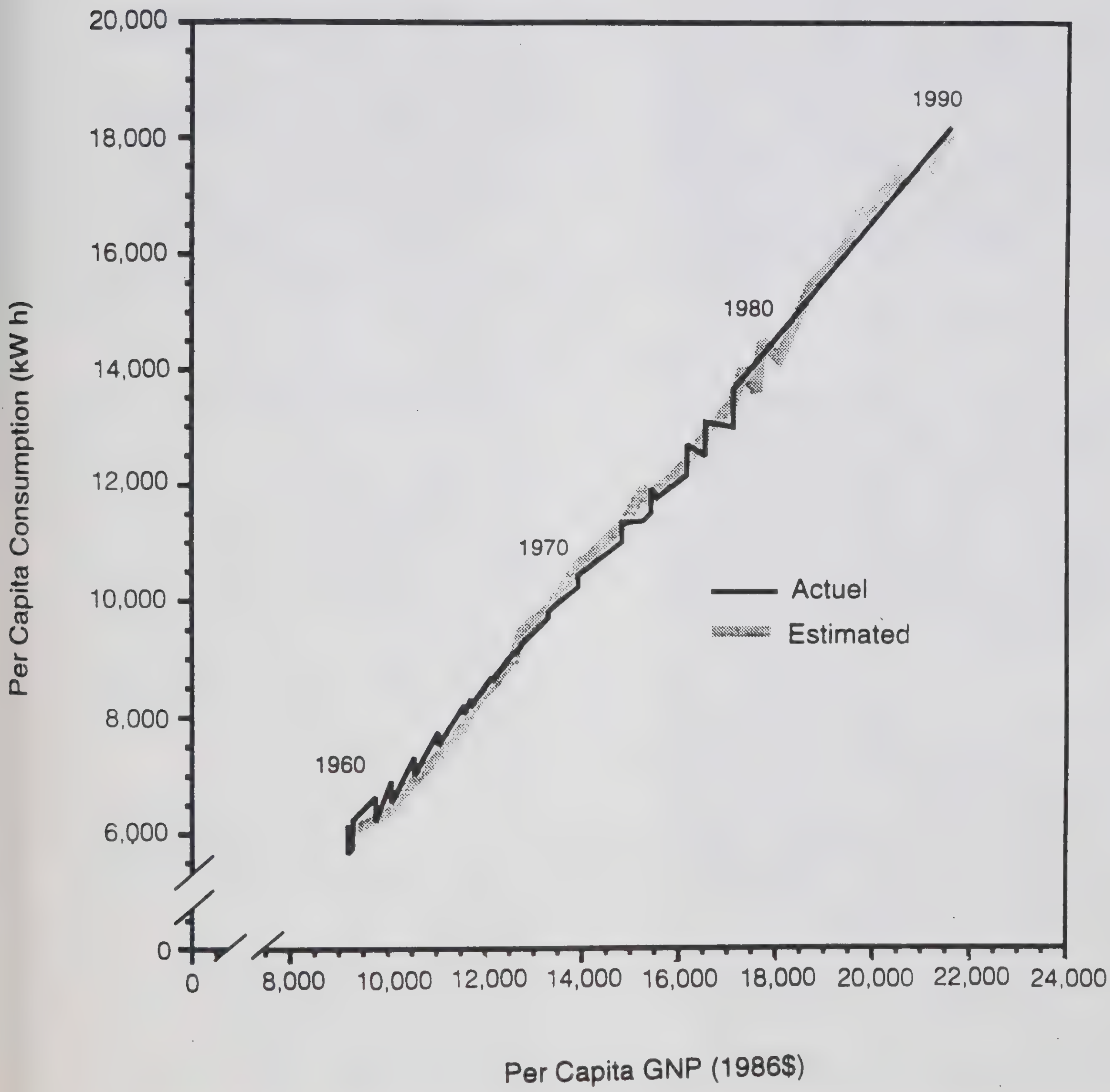


Figure 5.4 Historical Relationship between Electricity Demand and GDP, 1960-1993



Electricity Generation

Sources of Generation

Canada's electric power industry began in the 1880s with electricity generated by steam. In the beginning, electricity was used mainly for home and street lighting. In the late-1880s and 1890s, the invention of the electric motor dramatically changed the industry from one that mainly provided nighttime power for lighting to one that also provided power for transportation and industrial needs, 24 hours a day. Following this development, the use of hydroelectricity spread rapidly due to Canada's abundant water resources. In 1920, hydro accounted for more than 97 per cent of total electricity production in Canada. This percentage declined slightly to 95 per cent by 1950, and 92 per cent by the end of 1960. By 1994, hydro production had further declined to about 61 per cent (Table 6.1 and Figure 6.2).

Thermal generation, mainly from coal-fired stations, has been a part of Canada's generation mix since the beginning of the electric power industry. However, for many years its share of total production did not increase significantly because of its relatively high cost of production. This situation changed by the 1960s and 1970s, when most of Canada's economical hydro sites had been developed, and thermal generation became competitive.

Between 1950 and 1974, the growth rate of real fossil-fuel prices (coal, oil and natural gas) was negative -- a situation that led most electric utilities to build more thermal stations. As Table 6.1 indicates, thermal generation accounted for only 7 per cent of the total generated electricity in 1960. However, its production share jumped to 23 per cent by 1970, and reached a peak of 25 per cent in 1974. After the first oil crisis of 1973-74, fossil-fuel prices increased substantially, averaging more than 15 per cent during the 1975-85 period. As a result, the share of thermal production gradually declined to 22 per cent by 1980, and 20 per cent by 1985. With the collapse of oil prices in 1986, thermal generation once again became economical. As a result, thermal production's share rose to 22 per cent in 1990 and 1991, and up to 23 per cent in 1992. However, it was reduced to 20 per cent in 1994 attributing to the reduction of coal-fired generation because of environmental concerns.

The production of nuclear power began in Canada in 1962 when the 25-MW Rolphton station went into operation. In 1968, commercial operation started at the 220-MW Douglas Point station in Ontario, owned by Atomic Energy of Canada Ltd. During the 1970s, nuclear production emerged as an important source of electricity in Canada, and by 1975 nuclear generation accounted for more than 4 per cent of total electricity production. Most of the nuclear generation came from the first four Pickering stations in Ontario, which were completed between 1971-73. By 1980, the nuclear production share increased to about 10 per cent of Canada's total, with the completion of four of Ontario's Bruce stations.

By 1985, nuclear generation accounted for 13 per cent of Canada's total generated electricity. Between 1980 and 1985, seven nuclear stations were brought into service: Gentilly 2 in Quebec; Point Lepreau in New Brunswick; Pickering stations 5, 6 and 7, and Bruce stations 5 and 6, all located in Ontario. From 1986 to 1990, the nuclear generation share had increased to about 15 per cent with the commissioning of Pickering 8, Bruce 7 and 8, and Darlington 2, all of which went into operation in 1986, 1987, and 1990.

By 1994, nuclear generation's share increased to 17 per cent of total electricity generated in Canada due to the completion of the remaining three units of the Darlington Nuclear Station in 1992 and 1993.
To date, tidal power has played an insignificant role in electricity generation in Canada. However, it is worth noting that the 20-MW Annapolis tidal power plant in Nova Scotia, which began operation in 1984, is the first of its kind in North America. As compared to conventional hydro plants, this plant requires

higher maintenance levels because of salt water exposure. However, considering greater maintenance levels, the plant has operated without any major difficulties since 1984.

Hydroelectric Power Development

Canada's rapid development of hydroelectric power in the past was mainly attributed to two factors: abundant water resources and the nationalization of private provincial electric utilities. The former provided the least-cost energy production, and the latter enabled the provincial government to use the public enterprise as an instrument to serve government industrial policy and other objectives.

In the first half of the century, the influence of government objectives on the structure of the industry was mainly focusing on the level and structure of prices and the need for universal service - the types of concerns traditionally addressed through government control over monopolies. It was in this period that Ontario Hydro (1906), Hydro-Québec (1944), Manitoba Hydro (1949), and British Columbia Power Commission (1946) were created.

Since 1950, electric utilities have come to be seen in a broader context, especially for those provinces endowed with hydroelectric power resources. Given the amount and importance of their capital expenditures to provincial economies, it was recognized that hydroelectric power development could serve such policy objectives as job creation, industrial development, and macro-economic stabilization. During this more recent period, nationalizations occurred that led to a major expansion of the publicly owned electric utilities in British Columbia and Quebec.

During the 1960s, the provincial government assumed a major role in promoting the modernization of Quebec society and increased francophone control over the provincial economy. Government enterprise was one of the main instruments used to achieve those objectives.

The nationalization of the private electric utilities in the province was among the more dramatic initiatives taken during this period. While Hydro-Québec had been established since 1944, in the early 1960s over half the electric power in the province was still being provided by investor-owned firms. The nationalization that occurred in 1963 was in part justified by the need to integrate the system and coordinate investment. All major hydro projects (James Bay Phase I and Manic) in Quebec were developed after 1963 in coordination with industrial development and increased employment.

The same is true for British Columbia and Manitoba. British Columbia Hydro & Power Authority (B.C. Hydro) was incorporated in 1962 by merging B.C. Power Commission and B.C. Electric Limited which was nationalized in 1961. B.C. Hydro is a Crown corporation providing electrical service throughout the province, with the exception of the south interior, which is served by the West Kootenay Power and Light Company Limited. The most important hydro projects in British Columbia, Gordon M. Shrum, Revelstoke, and Mica, were all built after 1962 to serve the provincial government's policy purposes.

Manitoba Hydro's mandate under the 1970 *Manitoba Hydro Act* is to provide adequate power supply to meet the needs of the province and to promote economy and efficiency in the generation, distribution, supply, and use of power. With these government policy objectives, two major hydro projects, Kettle Rapide and Long Spruce, were commissioned in 1970 and 1977, respectively.

Electricity Generation in 1994

Electricity generation increased by 4.2 per cent in 1994, which is much greater than 1.3 per cent of the domestic electricity demand. The increase is mainly attributed to a greater number of exports to the United States and stronger domestic demand in Alberta and Saskatchewan. Of the total electricity generated in 1994, 482 496 GWh was for use in Canada and the remaining 51 012 GWh was exported. The sources of generation are given in Table 6.1, and the major generating stations in each province are shown in Figure 6.1.

Between 1960 and 1994, hydro production dropped from 92 per cent to 61 per cent, as shown in Figure 6.2. Natural gas production also decreased (from 4 per cent in 1960 to 2 per cent in 1994), while oil was stabilized at 1 per cent over the same period. With the first oil crisis of 1973-74, electric utilities were discouraged from using natural gas and oil for baseload electricity generation. However, as noted above, the collapse of oil prices in 1986 has made electricity generation from oil more economical.

Nuclear's share of production had the largest gain, moving from zero in 1960 to about 19 per cent by 1994; coal production increased from 3 per cent to 15 per cent over the same period. These increases have occurred at the expense of hydro. With the relatively cheap fuel prices of uranium and coal and the development of most of the country's economical hydro sites, hydro's share of production has declined significantly since 1960.

Electrical energy production by fuel type by province in 1994 is reported in Table 6.2. In Newfoundland, Quebec, and Manitoba, hydro generation accounted for more than 96 per cent of the total, and for 88 per cent in British Columbia. In Alberta, about 81 per cent of total generation came from coal. Coal generation was also important in Saskatchewan and Nova Scotia, at 72 per cent and 73 per cent respectively. In Ontario, coal, nuclear and hydro production are well balanced, while in New Brunswick, total generation is a mix of oil, nuclear, hydro and coal.

Ontario, Quebec and New Brunswick are the only three provinces that produce nuclear energy in Canada. In 1994, nuclear generation accounted for 61 per cent of Ontario's total electricity generation, 33 per cent of New Brunswick's, and 3 per cent of Quebec's. Electricity generation from natural gas occurs mainly in industries that generate power for their own use. In all provinces except Newfoundland, Nova Scotia and New Brunswick, oil is used mainly for peaking purposes.

Generation by Province

Table 6.3 shows electricity generation by province during the period 1960-94, and generation growth rates for 1994 over 1993 and the period 1960-94. Newfoundland had the greatest production growth during the period 1960-94, with an average growth rate of 10.0 per cent. This was due mainly to the completion of the Churchill Falls hydro station (5429 MW) in Labrador in 1974. Over 90 per cent of the electricity produced at Churchill Falls flows into Quebec under a contract that ends in the year 2041.

Electricity generation fluctuated significantly in Prince Edward Island during the period 1960-94. The province's electrical generating plants are relatively small, fuelled by oil, and are consequently expensive to operate. In 1977, an interprovincial interconnection was completed, allowing P.E.I. to purchase electrical energy from New Brunswick. In addition, in 1981, P.E.I. purchased a 10 per cent ownership interest in the 200-MW coal/oil-fired plant at Dalhousie, New Brunswick. However, P.E.I. had sold its ownership back to New Brunswick in 1994. The interconnection has enabled P.E.I. to reduce the amount of generation from its own oil-fired stations.

In 1994, there was negative growth in electricity generation in Newfoundland, P.E.I., and the Yukon (Table 6.3). The reduction of electricity generation in Newfoundland was mainly due to reduced sales to Quebec.

Figure 6.3 presents electricity generation by region. Although Quebec has been the largest electricity producer in Canada since 1960, its share has declined from 44 per cent in 1960 to 31 per cent in 1994. Ontario was the second-largest producer, with 28 per cent in 1994, compared with 31 per cent in 1960. British Columbia has remained the third largest electricity producer over the period, generally providing 12 per cent of the total. Electricity generation growth rates for Newfoundland, Nova Scotia, New Brunswick, Manitoba, Saskatchewan and Alberta were all greater than those for Quebec, Ontario and British Columbia during 1960-93. This indicates that generation shares for the Atlantic and Prairie provinces are increasing at the expense of the top three provinces.

Fossil-Fuel Requirements

Because of the rapid expansion of coal-fired stations in the 1960s and 1970s, coal consumption increased about tenfold during the period 1960-75, and more than doubled in the following ten years. However, in recent years, environmental concerns have led to a more gradual increase in its use.

The use of natural gas and oil for electricity generation peaked in the mid-1970s and 1980, and then declined sharply. However, with the collapse of international oil prices in 1986, the situation reversed itself and it again became economical for electric utilities to use oil and natural gas for electricity generation (Tables 6.4 and 6.5). The use of uranium has increased dramatically since 1970 with the growth of nuclear capacity in Canada, particularly in Ontario.

In 1994, provinces west of Quebec continued to use Canadian oil, primarily light oil and diesel oil, in gas turbines or diesel plants. In the Yukon and Northwest territories, Canadian diesel oil was used to supply electricity to small remote communities. Oil used by the Atlantic region and Quebec was imported.

In 1994, about 62 per cent of the coal used for electricity generation in Ontario was imported from the United States, while the remainder came from western Canada. Coal used by Manitoba was purchased from Saskatchewan, while Alberta, Nova Scotia and New Brunswick used their own coal resources. Saskatchewan relied primarily on its own coal, but also purchased additional amounts from Alberta.

Heat Content of Fuel

According to Statistics Canada, heat content for the same type of fuel used for electricity generation varies from province to province. For instance, Canadian bituminous coal used in Nova Scotia has 27 295 kilojouls per kilogram, compared with 18 026 kilojouls per kilogram in Alberta. The same is true for light, heavy, and diesel fuel oil used for electricity generation. Table 6.6 summarizes heat content for various fuels used in electricity generation in Canada in 1992.

Emissions from Electricity Generation

As shown in Table 6.1, 107 092 GWh of electricity came from conventional thermal sources, which accounted for about 20 per cent of total electricity generated in 1994. This amount of thermal generation required a considerable quantity of fossil fuels: 46 million tonnes of coal; 2.5 million cubic metres of oil; and 3219 million cubic metres of natural gas (Table 6.5). In 1994, about 88 per cent of the

total coal consumption in Canada was used for electricity generation. The percentage shares for natural gas and oil are 4.0 per cent and 2.5 per cent, respectively.

The combustion of fossil fuels can produce carbon dioxide, sulphur dioxide, nitrous oxides, etc. Emissions from electricity generation in 1994 are presented in Table 6.7. In 1994, about 20 per cent of the total carbon dioxide emission in Canada came from the electric power industry.

Tables and figures referred to in this chapter are on the following pages.

Tables & Figures

Table 6.1
Sources of Electricity Generation

Fuel Type	Electricity Generation 1960	1970	1980	1990	1993	1994	Average Annual Growth Rate 1960-94	1993-94
	(GWh)						(per cent)	
Hydro	105 883	156 709	251 217	292 810	319 070	324 654	3.4	1.8
Thermal	8 495	47 045	80 207	104 121	104 046	107 092	7.7	2.9
Nuclear*	-	969	35 882	68 837	88620	101 730	-	14.8
Tidal**	-	-	-	26	33	32	-	-3.0
Total	**114 378**	**204 723**	**367 306**	**465 744**	**511 769**	**533 508**	**4.6**	**4.2**

* Commercial operation started in 1968.
** Commercial operation started in 1984.

Source: Electric Power Statistics, Volume (II), Statistics Canada, catalogue 57-202, and Electric Power Statistics Monthly, Statistics Canada, catalogue 57-001

Table 6.2
Electrical Energy Production by Fuel Type, 1994

	Coal	Oil	Natural Gas	Nuclear	Hydro	Other	Total
			(GWh)				
Nfld.	0	867	0	0	37 538	0	38 405
P.E.I.	0	40	0	0	0	0	40
N.S.	7 160	1 397	0	0	1 048	155	9 760
N.B.	5 273	2 071	0	5 238	2 741	544	15 867
Quebec	0	317	25	5 406	157 176	0	162 899
Ontario	14 873	156	3 361	91 086	38 390	567	148 433
Manitoba	206	6	23	0	28 146	54	28 435
Sask.	11 214	47	639	0	3 393	178	15 471
Alberta	42 478	83	6 629	0	1 809	1 296	52 295
B.C.	0	793	4 749	0	53 979	1 494	61 015
Yukon	0	36	0	0	261	0	297
N.W.T.	0	292	94	0	205	0	591
Canada	**81 204**	**6 105**	**15 495**	**101 730**	**324 686**	**4 288**	**533 508**

Source: Natural Resources Canada

Table 6.3
Electricity Generation by Province

	Electricity Generation						Average Annual Growth Rate	
	1960	1970	1980	1990	1993	1994	1960-1994	1993-1994
	(GWh)						(%)	
Nfld.	1 512	4 854	46 374	36 585	40 846	38 405	10.0	-6.0
P.E.I.	79	250	127	81	59	40	-2.0	-32.2
N.S.	1 814	3 511	6 868	9 430	9 714	9 760	5.1	0.5
N.B.	1 738	5 142	9 323	16 665	15 112	15 876	6.7	5.0
Quebec	50 433	75 877	97 917	135 458	154 443	162 899	3.5	5.5
Ontario	35 815	63 857	110 283	129 343	140 870	148 433	4.3	5.4
Manitoba	3 742	8 449	19 468	20 149	27 121	28 435	6.2	4.8
Sask.	2 204	6 011	9 204	13 540	15 303	15 471	5.9	1.1
Alberta	3 443	10 035	23 451	42 874	48 556	52 295	8.3	7.7
B.C.	13 409	26 209	43 416	60 662	58 822	61 015	4.6	3.7
Yukon	89	224	381	485	335	297	3.6	-11.3
N.W.T.	100	304	494	472	588	591	5.4	0.5
Canada	114 378	204 723	367 306	464 744	511 769	533 508	4.6	4.2

Source: Electric Power Statististics, Volume (II), Statistics Canada, catalogue 57-202

Table 6.4
Fuels Used to Generate Electricity in Canada

	1960	1965	1970	1975	1980	1985	1990	1993	1994
Coal (10^3) tonnes	1 674	7 004	13 786	16 567	27 785	39 456	41 822	42 791	46 418
Oil (10^3) cubic metres	328	871	1 869	2 309	2 867	1 391	3 888	2 686	2 453
Natural Gas (10^3) cubic metres	1 069	1 679	1 992	4 009	1 875	1 223	3 084	3 459	3 219
Uranium (tonnes)	0	2	16	194	685	1 086	1 386	1 619	1 740

Source: Electric Power Statistics, Volume (II), Statistics Canada, catalogue 57-202, and Natural Resources Canada

Table 6.5
Fuels Used to Generate Electricity by Province, 1994*

	Coal (10^3 tonnes)	Oil (10^3 cubic metres)	Gas (10^6 cubic metres)	Uranium (tonnes)
Nfld.	0	203	0	0
P.E.I.	0	18	0	0
N.S.	2 678	340	0	0
N.B.	1 144	1 030	0	100
Quebec	0	606	3	101
Ontario	5 527	0	764	1 539
Manitoba	149	0	1	0
Sask.	9 154	7	184	0
Alberta	27 766	6	1 395	0
B.C.	0	148	842	0
Yukon	0	9	0	0
N.W.T.	0	86	30	0
Canada	**46 418**	**2 453**	**3 219**	**1 740**

Note: 1 cubic metre oil = 6.3 barrels; 1 barrel of oil is defined as 5 800 000/BTU.
1 cubic metre gas = 35.5 cubic feet; 1 cubic foot of natural gas is defined as 1000 BTU.
1 tonne = 1000 kilograms; 1 gram of uranium is defined as 603 825 BTU.
* Preliminary Data

Source: Natural Resources Canada

Table 6.6
Heat Content in Canada, 1992

	Canadian Bituminous (kg)	Imported Bituminous (kg)	Sub-Bituminous (kg)	Lignite (kg)	Light Fuel Oil (litre)	Heavy Fuel Oil (litre)	Diesel (litre)	Natural Gas (m^3)	Uranium (g)
					(kilojouls)				
Nfld.	-	-	-	-	38 339	42 465	38 168	-	-
P.E.I.	-	-	-	-	-	41 497	35 726	-	-
N.S.	27 295	-	-	-	37 580	41 932	37 581	-	-
N.B.	26 901	-	-	-	38 740	41 409	39 133	-	576 200
Que.	-	-	-	-	41 381	41 608	38 680	-	632 000
Ont.	25 707	30 110	-	16 121	38 544	41 432	37 696	37 719	704 549
Man.	-	-	-	-	37 814	-	35 712	37 223	-
Sask.		-	-	16 282	37 100	-	38 000	36 523	-
Alta.	18 026	-	18 364	-	-	-	37 956	38 128	-
B.C.	-	-	-	-	-	-	36 162	38 499	-
Yukon	-	-	-	-	-	-	57 000	-	-
N.W.T.	-	-	-	-	-	-	37 001	-	-
Canada	**25 678**	**30 110**	**18 364**	**14 784**	**38 808**	**41 682**	**37 319**	**37 935**	**693 961**

Source: Electric Power Statistics Volume II, Statistics Canada, Catalogue 57-202

Table 6.7
Emissions from Electricity Generation, 1994

	SO_2 (1000 tonnes)	NO_x (1000 tonnes)	CO_2 (1000 tonnes)
Newfoundland	9	2	660
Prince Edward Island	1	0	53
Nova Scotia	133	0	7 227
New Brunswick	90	17	6 354
Quebec	2	1	274
Ontario	71	28	14 827
Manitoba	1	0	243
Saskatchewan	76	29	12 931
Alberta	157	89	50 366
British Columbia	0	2	1 444
Yukon	1	0	27
Northwest Territories	1	0	252
Electric Utilities' Total	542	168	94 658
Canada's Total Resulting from Energy Activities	-	-	474 800
Electric Utilities' Share (%)	-	-	20

Source: Electric Utilities and Natural Resources Canada

Figure 6.1 Major Generating Stations by Province, 1994 (MW)

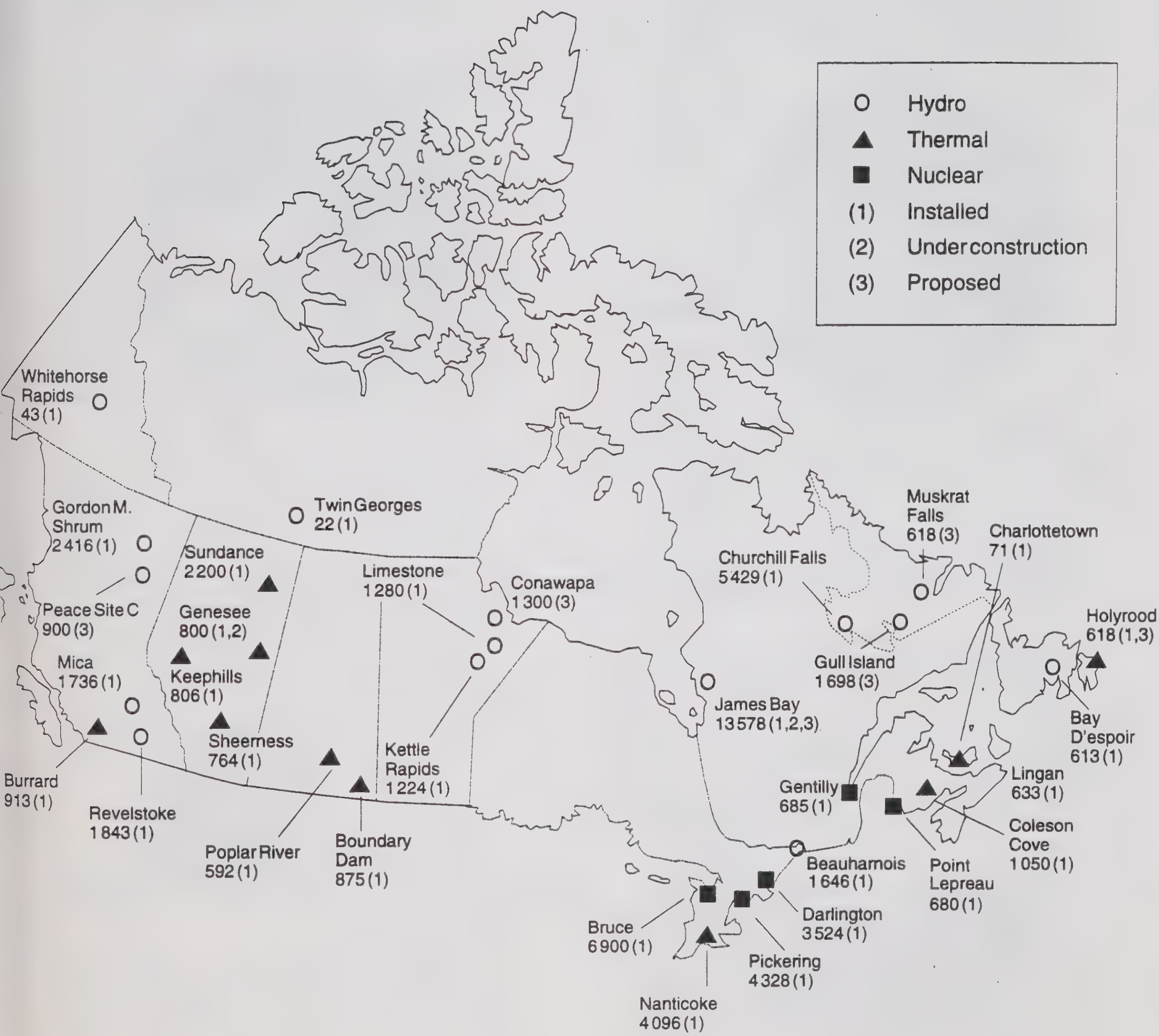


Figure 6.2 Electricity Generation by Fuel Type

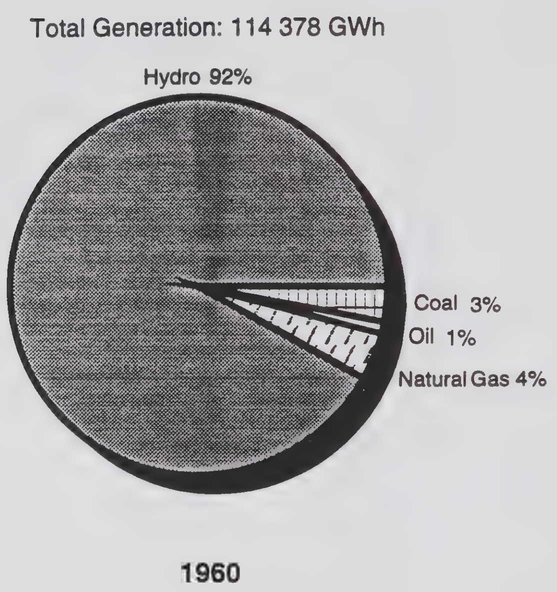
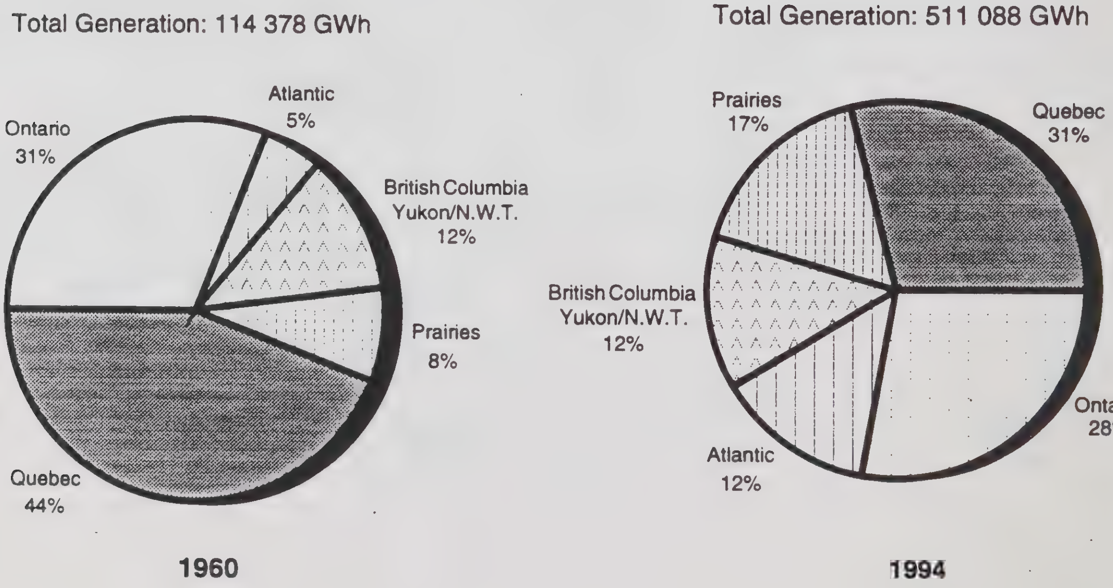


Figure 6.3 Electricity Generation by Region



Generating Capacity and Reserve

To meet load requirements, an electric power system must have sufficient installed generating capacity to satisfy the peak demand and the capability to supply the total energy requirements.

As discussed in Chapter 6, Canada's first electrical generating stations were thermal. As the demand for electricity grew and technology developed, hydroelectric power grew in importance, primarily for economic reasons. The use of hydroelectricity spread rapidly due to Canada's abundant water resources.

In 1920, hydro accounted for 86 per cent of total generating capacity, and by 1945, hydro's share of total installed capacity peaked at 94 per cent. Since then, the capacity share of hydro has declined gradually, reaching about 81 per cent by 1960, 58 per cent in 1980, and 56 per cent in 1994 (Table 7.1).

Several factors have contributed to the gradual reduction in the capacity share of hydro since the end of World War II. By 1945, many of Canada's economic hydro sites had been developed. Moreover, the growth rates of real fossil-fuel prices (coal, oil and natural gas) were negative between 1950 and 1974, a situation that led many utilities to construct thermal stations during this period. In addition, in the early 1960s, Canada began to develop nuclear energy as an alternative means of electricity generation.

Capacity Additions

There were only a few major capacity additions in 1994. This may be a result of energy conservation efforts and economic recession. New major additions were about 1672 MW in 1994. Of this total, hydro accounted for 1266 MW, followed by coal 406 MW.

Between October and December 1994, a 67 MW hydro generating unit went into service at Hydro-Québec's Manic 5 power station, as did four units (4x136 MW) at the La Forge 1 hydro station. In addition, the six units of the 2x110 MW and 4x100 MW at the LG - 1 hydro station were also completed in 1994.

The second unit of 406 MW at the Genesee coal-fired station, owned by Edmonton Power was declared in-service in October 1994.

Capacity by Fuel Type and Province

Total installed capacity by fuel type and province for 1994 is given in Table 7.2. Although hydro's share of total installed capacity has declined, hydro is still the predominant source of electrical energy in Canada. In 1994, hydro's capacity share accounted for 56 per cent of total installed capacity, followed by coal 18 per cent, nuclear 14 per cent, oil 7 per cent, natural gas 4 per cent, and other (wood, flare gas, etc.) 1 per cent (Figure 7.1).

In the 1960s and early-1970s, Quebec had the largest installed capacity in Canada. Since the mid-1970s, however, Ontario's capacity has been the largest. In 1994, Ontario's installed capacity was 32 per cent of the Canadian total, followed by Quebec with 29 per cent and British Columbia with 12 per cent. The combined total of these three provincial electrical systems accounted for 73 per cent of the total. Between 1960 and 1994, the Atlantic provinces had a major gain; their share increased from 5 per cent in 1960 to 12 per cent by 1994. This increase was due to the completion of the Churchill Falls project in Labrador in 1974, (Figure 7.2). Table 7.3 presents installed generating capacity by province for the period 1960-94.

Major Hydro Stations in Canada

Canada is a world leader in large hydro-station design, construction and operation. Table 7.4 lists Canada's ten largest hydro stations in 1994. Churchill Falls, Canada's largest hydro plant (5429 MW), ranked sixth among the world's hydro plants by present capacity. La Grande 2, situated in the James Bay region of Quebec, is Canada's second-largest hydro plant with 5328 MW and ranked seventh in the world. La Grande 4, also in Quebec, ranked seventeenth. British Columbia's Gordon M. Shrum hydro plant and Quebec's La Grande 3 ranked twenty-first and twenty-third among the world's largest hydro plants in 1994[1].

Among Canada's ten largest hydro plants, five are located in Quebec, mainly in the James Bay area, three in British Columbia, and one each in Newfoundland and Manitoba. These ten hydro stations have a total installed capacity of 26 362 MW, and in 1994 they accounted for about 42 per cent of Canada's total hydro capacity. Many smaller, but strategically important, hydro facilities are located throughout the country.

Major Conventional Thermal (Fossil) Stations in Canada

Canada has significant long-term experience with a variety of thermal technologies of all sizes. In the 1950s and early-1960s, Canadian electric utilities built many steam plants with unit sizes from tens of MW to as large as 300 MW. Since then, advances in technology, stable fossil-fuel prices, and robust electricity demand growth have supported the development of larger steam plants. For example, Ontario Hydro's Lambton and Nanticoke coal-fired stations have unit sizes of 510 MW and 512 MW respectively, while the Lennox oil-fired station has four units of 550 MW. Electric utilities in Alberta and New Brunswick have constructed a number of coal-fired stations with unit sizes in the 400 MW range.

Table 7.5 lists Canada's ten largest thermal stations in 1994 Seven of the ten stations are using coal as input fuel, two oil and one natural gas. Five of the ten largest thermal stations are located in Ontario, where a large population results in significant economies of scale. Two of the stations are in Alberta, and there is one each in New Brunswick, Saskatchewan and British Columbia. Total combined capacity for these stations is 17 790 MW, which accounted for 54 per cent of Canada's total conventional thermal installed capacity in 1994.

Nuclear Power Stations in Canada

In the early-1960s, Canada started to develop nuclear energy as an alternative source for future energy demand. By 1994, Canada owned and operated 22 large CANDU reactors (500 MW and up), with a total installed net capacity of 16 393 MW. With the exceptions of Point Lepreau 1 in New Brunswick and Gentilly 2 in Quebec, they are all located in Ontario. Table 7.6 reports major nuclear power stations in Canada, in order of their commissioning date. CANDU reactors (pressurized heavy water reactors) have been shown to be among the best nuclear reactors in the world in terms of cost-effectiveness, safety measures and output performance. Figure 7.3 indicates that among lifetime performance for five types of nuclear reactors (over 150 MW), the CANDU has the highest capacity factor to December 31, 1994. In terms of lifetime performance for nuclear reactors over 500 MW worldwide, Canada's CANDU reactors comprised three of the ten best reactors, and New Brunswick Power's Point Lepreau was ranked second (Figure 7.4).

[1] *International Water Power and Dam Construction, Handbook 1993.*

Surplus Capacity

Electric utilities are empowered with the difficult task of anticipating future electricity demand and ensuring that there are sufficient new generating facilities planned and built to supply the actual need.

During periods of fluctuating demand, such as we are experiencing now, this task provides a significant challenge. On occasion, when new generating facilities are completed and the expected demand does not materialize, the utility is faced with excess generating capacity. In the early-1970s, the construction of new generating stations was initiated mainly on the basis of expectations of continuing rapid growth in electricity demand. However, growth in demand slowed dramatically in the latter part of the decade and some of these newly constructed stations were temporarily surplus to domestic requirements.

In calculating surplus capacity, the generating capability, rather than generating capacity, is normally used. Generating capability measures the expected output of all the available generating facilities in a region at the time of firm peak load. This may differ significantly from the generating capacity measured by the nameplate rating of the equipment.

The variations between generating capability and generating capacity may be caused by a number of factors. These include: water levels in hydro reservoirs, the combined effects of derates and outages, weather effects, and fuel availability.

Reserve Margin

The reserve margin of an electrical system can be defined as the excess of generating capability for in-province use, over the in-province firm peak that occurred during the year, expressed as a percentage of in-province firm peak. Table 7.7 presents the reserve margins of the ten provinces and two territories in 1994. Utilities in the Yukon and Northwest territories have high reserve margins because of the logistics associated with serving remote communities. The extra generators allow the utilities to continue to provide service in the event of equipment failure. Where many communities can be connected together via an electric grid and facilities can be shared, the capacity reserve requirement can be reduced substantially.

Capacity Reserve Requirements

Normal practice in an electrical system is to reserve a certain amount of capacity (expressed as a percentage of firm peak load) to allow for scheduled maintenance, derates or failure of equipment and fluctuations in demand. This portion is usually called the capacity reserve requirement, and it varies from utility to utility, depending on the configuration and requirements of the particular system. Column 4 of Table 7.7 reports the capacity reserve requirement in each province and territory for 1994.

Net Surplus Capacity

Net surplus capacity is defined as the reserve margin less the reserve capacity requirement. Table 7.7 indicates existing net surplus generating capacity by province and for Canada as a whole for 1994. With the exceptions of Prince Edward Island, Ontario, and British Columbia, all provinces and territories had net surplus capacity by the end of 1994. A weighted average for Canada was only one per cent. Regions which have low generating capability

rely on interconnections with neighbouring electrical systems to meet their peak requirements.

Hydroelectric Potential in Canada

There is still a large amount of undeveloped hydroelectric potential in Canada (Table 7.8). Although much of this is unlikely to be developed due to the remoteness of the sites, the physical difficulty of the terrain or environmental concerns, a significant amount could be developed over the next 25 years.

Tables and figures referred to in this chapter are on the following pages.

Tables & Figures

Table 7.1
Installed Generating Capacity by Fuel Type, 1960-1994

Fuel Type	Installed Generating Capacity						Average Annual Growth Rate	
	1960	1970	1980	1990	1993	1994	1960-1994	1993-1994
	(MW)						(per cent)	
Hydro	18 643	28 298	47 770	58 701	62 027	63 244	3.7	2.0
Thermal	4 392	14 287	28 363	31 174	33 765	34 250	6.2	1.4
Nuclear*	0	240	5 866	13 052	16 393	16 393	-	0.0
Tidal**	0	0	0	20	20	20	-	0.0
Total	**23 035**	**42 825**	**81 999**	**102 947**	**112 205**	**113 877**	**4.8**	**1.5**

* Commercial operation started in 1968.
** Commercial operation started in 1984.
Source: Electric Power Statistics, Volume II, Statistics Canada, catalogue 57-202

Table 7.2
Installed Generating Capacity by Fuel Type and Province, 1994

	Coal	Oil	Natural Gas	Nuclear	Hydro	Other	Total
				(MW)			
Nfld.	0	798	0	0	6 650	5	7 453
P.E.I.	0	121	0	0	0	0	121
N.S.	1 317	589	0	0	390	18	2 314
N.B.	808	1 883	0	680	903	104	4 378
Que.	0	1 543	101	685	30 581	5	32 906
Ont.	10 653	2 710	846	15 028	7 204	132	36 573
Man.	369	17	4	0	4 498	23	4 911
Sask.	1 766	22	433	0	836	22	3 079
Alta.	5 987	18	1 766	0	823	193	8 787
B.C.	0	227	1 031	0	11 223	528	13 009
Yukon	0	57	0	0	77	0	134
N.W.T.	0	143	20	0	49	0	212
Canada	**20 900**	**8 119**	**4 201**	**16 393**	**63 234**	**1 030**	**113 877**

Source: Electric Power Statistics, Volume II, Statistics Canada, catalogue 57-204 and Natural Resources Canada

Table 7.3
Installed Generating Capacity by Province, 1960-1994

	Installed Generating Capacity						Average Annual Growth Rate	
	1960	1970	1980	1990	1993	1994	1960-1994	1993-1994
	(MW)							
Nfld.	314	1 248	7 195	7 462	7 453	7 453	9.8	0.0
P.E.I.	37	77	118	122	121	121	3.5	0.0
N.S.	507	931	2 029	2 156	2 314	2 314	4.6	0.0
N.B.	402	1 201	2 795	3 543	4 378	4 378	7.3	0.0
Quebec	8 920	14 047	20 531	28 873	31 640	32 906	3.9	4.0
Ontario	7 109	13 700	25 796	32 733	36 573	36 573	4.9	0.0
Manitoba	1 043	1 794	4 142	4 414	4 911	4 911	4.7	0.0
Sask.	761	1 533	2 340	2 846	3 079	3 079	4.2	0.0
Alberta	915	2 674	5 807	7 976	8 381	8 787	6.9	4.8
B.C.	2 963	5 473	10 525	12 497	13 009	13 009	4.4	0.0
Yukon	31	58	94	126	134	134	5.6	0.0
N.W.T.	33	89	180	199	212	212	5.6	0.0
Canada	**23 035**	**42 825**	**81 999***	**102 947**	**112 205**	**113 877**	**4.8**	**1.5**

* Includes confidential data, not available by province.
Source: Electric Power Statistics, Volume II, Statistics Canada, catalogue 57-202

Table 7.4
Canada's Largest Hydro Stations, 1994

Rank	Name	Province	Rated Capacity (MW)	Year of Initial Operation
1	Churchill Falls	Newfoundland	5 429	1971
2	La Grande 2	Quebec	5 328	1979
3	Gordon M. Shrum	B.C.	2 730	1968
4	La Grande 4	Quebec	2 651	1984
5	La Grande 3	Quebec	2 304	1982
6	Revelstoke	B.C.	1 843	1984
7	Mica	B.C.	1 736	1976
8	Beauharnois	Quebec	1 648	1932
9	Manic 5	Quebec	1 469	1970
10	Limestone	Manitoba	1 224	1990

Source: Electric Power Statistics,Volume III, Statistics Canada, catalogue 57-206, 1992

Table 7.5
Canada's Largest Conventional Thermal Stations, 1994

Rank	Name	Fuel Type	Province	Rated Capacity(MW)	Year of Initial Operation
1	Nanticoke	coal	Ontario	4 096	1973
2	Lakeview	coal	Ontario	2 400	1962
3	Lennox	oil	Ontario	2 200	1976
4	Sundance	coal	Alberta	2 200	1970
5	Lambton	coal	Ontario	2 040	1969
6	Richard L. Hearn	coal	Ontario	1 200	1951
7	Coleson Cove	oil	New Brunswick	1 050	1976
8	Burrard	natural gas	British Columbia	913	1961
9	Boundary Dam	coal	Saskatchewan	875	1959
10	Genesee	coal	Alberta	816	1899

Source: Electric Power Statistics, Volume III, Statistics Canada, catalogue 57-206, 1993

Table 7.6
Commercial Nuclear Power Plants in Canada, 1994

Rank	Plant Name	Province	Rated Net Capacity (MW)	Commissioning Date
1	Pickering A1	Ontario	515	1971
2	Pickering A2	Ontario	515	1971
3	Pickering A3	Ontario	515	1972
4	Pickering A4	Ontario	515	1973
5	Bruce A1	Ontario	769	1977
6	Bruce A2	Ontario	769	1977
7	Bruce A3	Ontario	769	1978
8	Bruce A4	Ontario	769	1979
9	Point Lepreau 1	New Brunswick	635	1983
10	Pickering B5	Ontario	516	1983
11	Gentilly 2	Quebec	638	1983
12	Pickering B6	Ontario	516	1984
13	Bruce B6	Ontario	837	1984
14	Pickering B7	Ontario	516	1985
15	Bruce B5	Ontario	860	1985
16	Pickering B8	Ontario	516	1986
17	Bruce B7	Ontario	860	1986
18	Bruce B8	Ontario	837	1987
19	Darlington 2	Ontario	881	1990
20	Darlington 1	Ontario	881	1992
21	Darlington 3	Ontario	881	1993
22	Darlington 4	Ontario	881	1993

Source: Electricity Branch, Natural Resources Canada

Table 7.7
Surplus Capacity in Canada, 1994

	Net Generating Capability for In-Province Use (1)	In-Province Firm Peak (2)	Reserve Margin (3)= ((1)-(2)) / (2)	Capacity Reserve Requirement (4)*	Net Surplus Capacity (5)=(3)-(4)
	(MW)			(per cent)	
Nfld.**	2 248	1 820	24	17	7
P.E.I.	160	148	8	15	-7
N.S.	2 207	1 731	28	20	8
N.B.	3 746	2 853	31	20	11
Quebec	37299	33 755	11	10	1
Ontario	32 274	26 718	21	24	-3
Manitoba	4 537	3 268	39	15	24
Sask.	2 937	2 525	16	15	1
Alberta	8 738	6 965	26	22	4
B.C.	11 036	10 227	8	15	-7
Yukon	135	62	118	19	99
N.W.T.	251	95	164	30	134
Canada	**106 091**	**90 167**	**18**	**17**	**1**

*Expressed as a percentage of in-province firm peak.
**Includes Labrador.

Source: Electric Power Statistics, Volume I, Statistics Canada, catalogue 57-204

Table 7.8
Hydroelectric Capacity in Canada, 1994

Province/Territory	In-Operation and Under Construction	Remaining Potential		
		Gross*	Identified**	Planning***
		(MW)		
Newfoundland	6 650	5 201	4 623	2 555
Prince Edward Island	0	0	0	0
Nova Scotia	390	8 499	8 499	0
New Brunswick	903	940	600	440
Quebec	32 394	66 286	34 844	7 858
Ontario	7 204	12 385	12 385	4 008
Manitoba	4 498	8 360	5 260	5 260
Saskatchewan	836	2 189	935	870
Alberta	823	18 813	9 762	1 833
British Columbia	11 223	33 137	18 168	10 164
Yukon	77	18 583	13 701	350
Northwest Territories	49	9 229	9 201	2 473
Canada	**65 047**	**183 622**	**117 978**	**35 811**

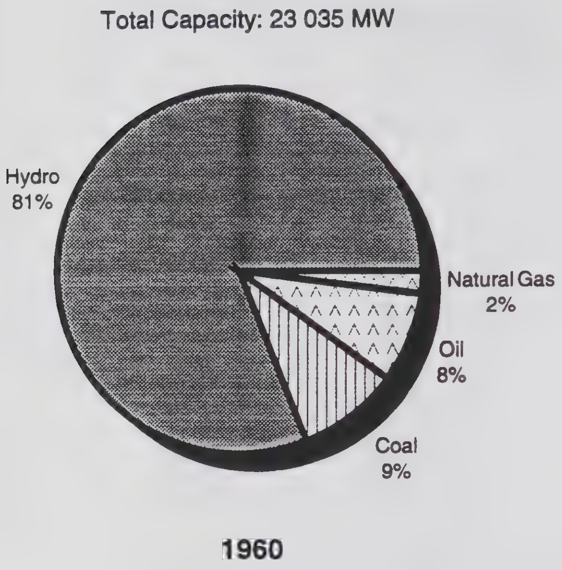
* Gross Potential – The total gross resource that could be developed if there were no technical, economic or environmental constraints (excludes sites already developed or under construction).

** Identified Potential – Gross potential less sites that may not be developed for technical reasons.

*** Planning Potential – Identified potential less sites that may not be developed for environmental or economic reasons. The planning potential thus comprises all those sites that are considered to be likely candidates for future development.

Source: Canadian electrical utilities and Natural Resources Canada

Figure 7.1 Installed Generating Capacity by Fuel Type



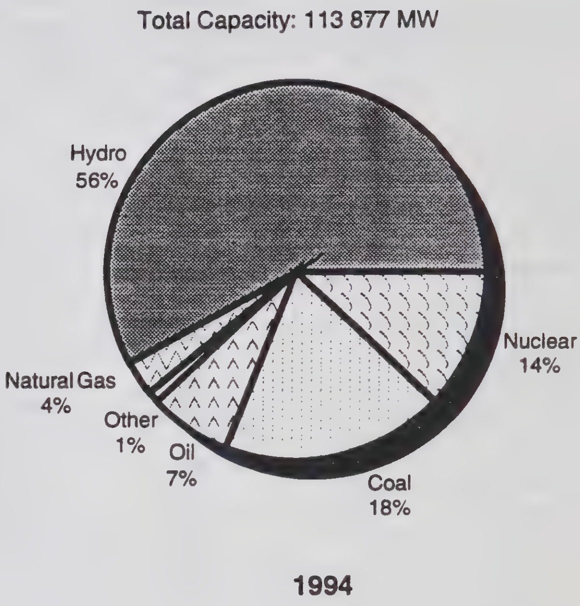
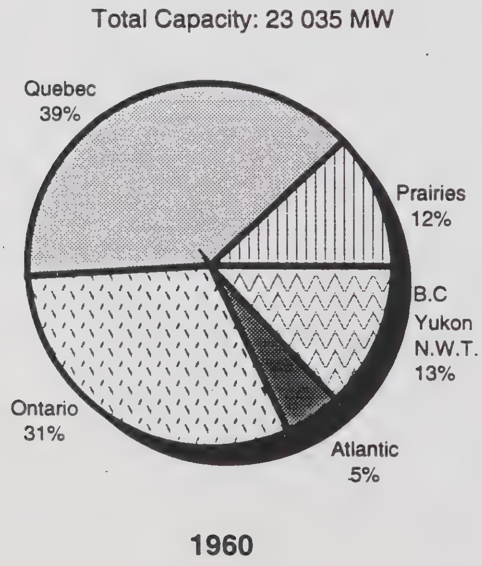


Figure 7.2 Installed Generating Capacity by Region



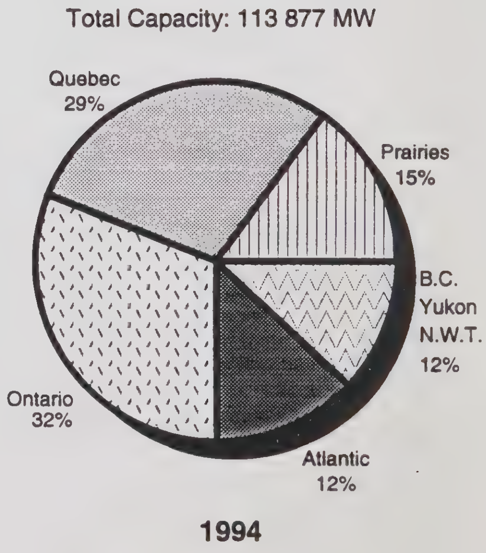
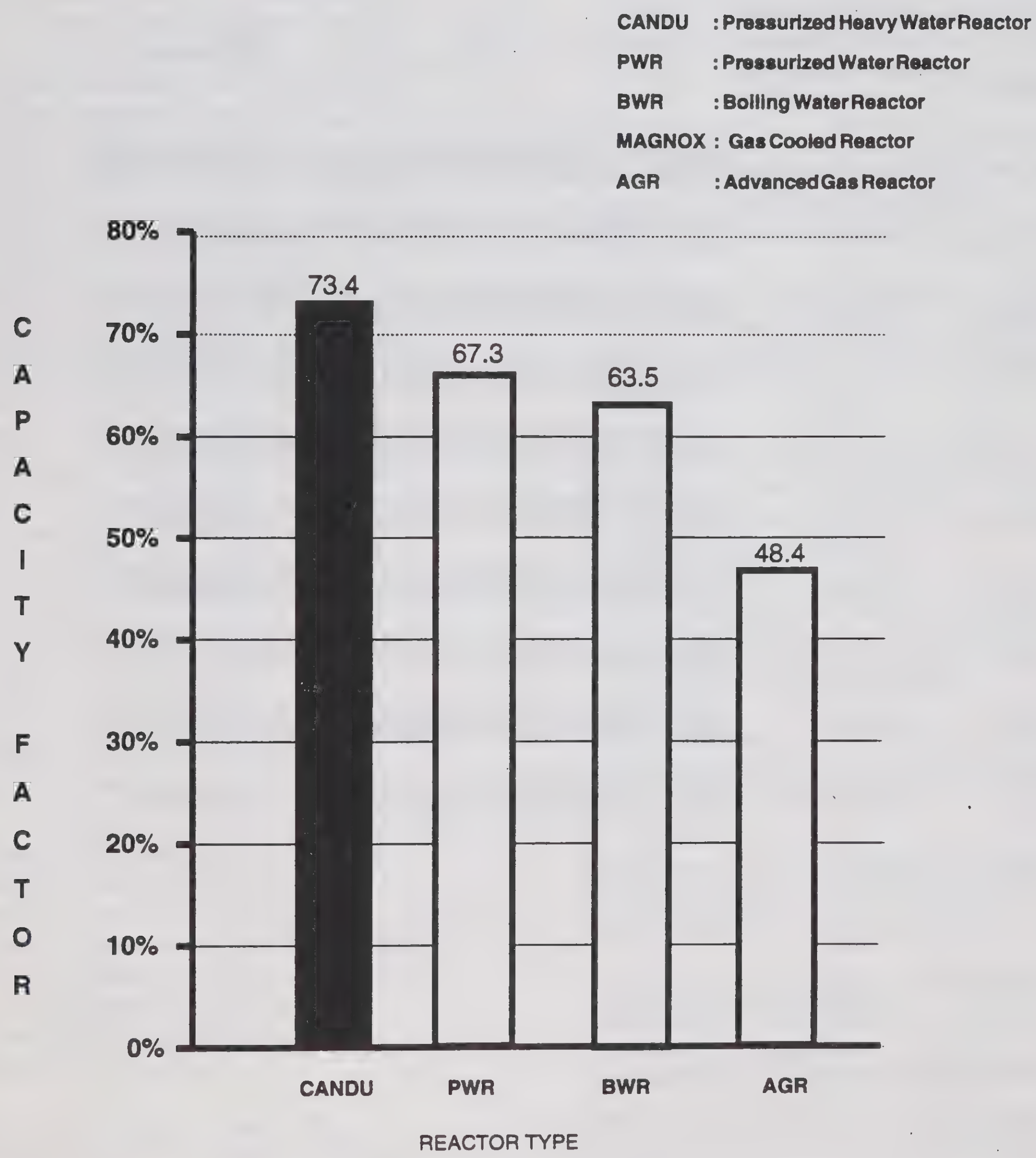


Figure 7.3 Nuclear Reactor Performance Worldwide by Type*

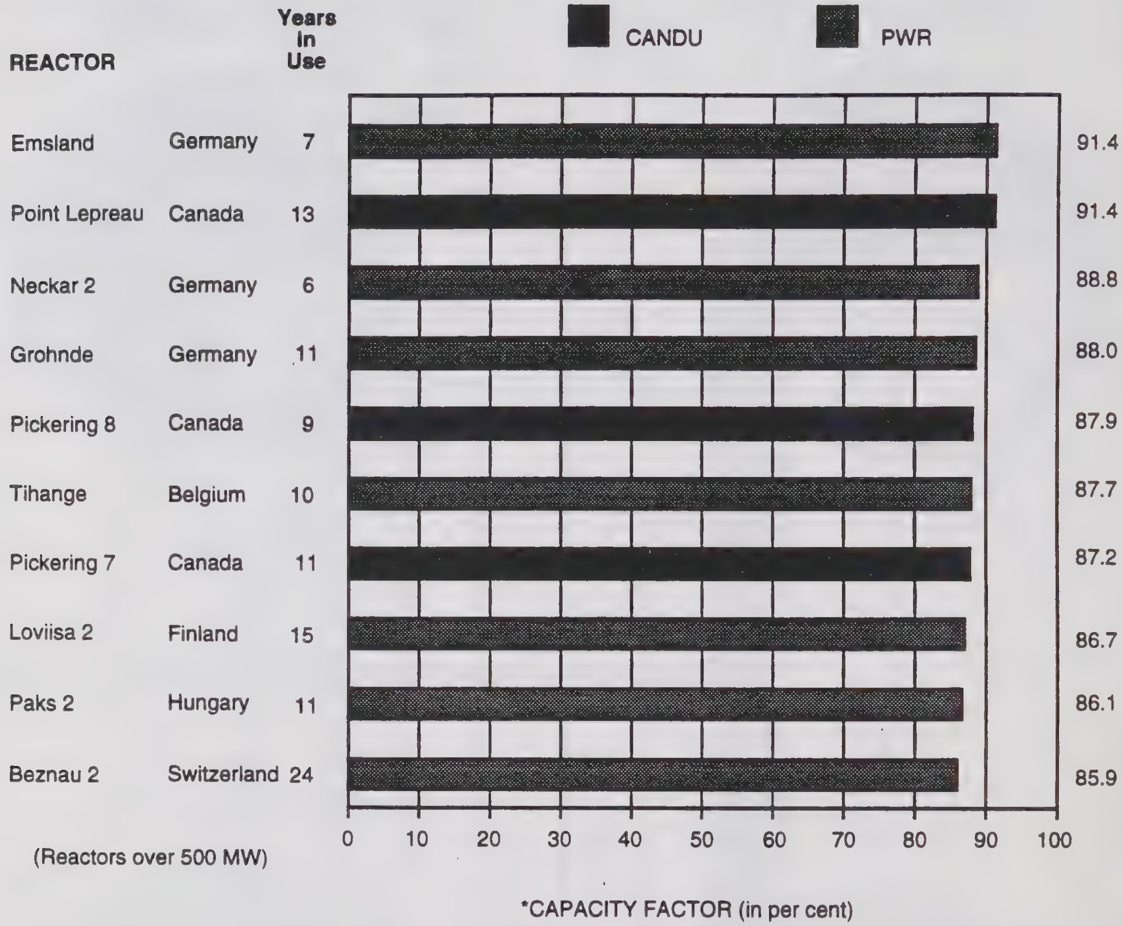


Reactors > 150 MW

* Lifetime to end of December 31, 1994

Source: World Nuclear Industry Handbook 1993 and Atomic Energy of Canada Ltd.

Figure 7.4 World Nuclear Reactor Performance to December 31, 1994



* Capacity factor = $\frac{\text{actual eletricity generation}}{\text{perfect electricity generation}}$

Source: Nuclear Engineering International, April 1994

Chapter 8

Electricity Trade

International Trade

Electricity trade between Canada and the United States dates back to the beginning of the century. In 1901, the first electric power transmission line between the two countries was built at Niagara Falls which enabled abundant Canadian hydroelectric power to be marketed in the United States. This historical event set the stage for continued electricity exchanges between the two countries in a climate of international cooperation and coordination. During the early years, Canadian electricity exports to the U.S. were usually in the form of long-term firm power sales contracts because Canada needed the export contracts to finance construction of hydroelectric plants. Both Canadian and U.S. companies invested in generating capacity built in Canada for export.

Since 1921, electricity trade has been in Canada's favour in terms of quantity. Canada's net exports grew substantially from the early-1970's reaching a peak of 45 TWh in 1987, largely due to the high cost of thermal production in the United States.

Electricity trade between the United States and Canada is mainly attributed to the following:

- differences in the natural resources of the two countries have a significant impact on the level of trade. For instance, many Canadian provinces, such as Newfoundland, Quebec, Manitoba, and British Columbia have an abundance of hydroelectric resources that can be substituted for U.S. generation from fossil fuels;

- cost differences stimulate the selling of Canadian power to U.S. markets for profit;

- electric utilities benefit from the purchase of less costly Canadian supplies; and

- electrical energy supply systems in the U.S. and Canada have differences in seasonal peak demands, which makes surplus energy exchanges possible. While all electrical systems in Canada have their peak demand in winter, all electrical systems in the United States have their peak in summer.

Electricity trade between the United States and Canada provides a wide variety of benefits to consumers and electric utilities in both countries. These benefits include:

- *rate reduction:* electric utilities normally use export revenues to reduce their revenue requirements, which, in turn, reduces rate increases;

- *surplus energy sales:* the existence of secondary markets, including storage, to utilize energy from renewable resources that would otherwise be wasted;

- *economy interchange:* the interchange of electricity between two utilities which results in a reduction of production costs;

- *diversity exchange:* non-coincident peak loads which allow utilities to share generation and realize economic benefits;

- *reserve sharing:* agreements for mutual generation support so that new power plant requirements are decreased; and

- *coordination of planning and operation:* cooperation between utilities, mainly in generation facility planning, operation, and maintenance, to reduce investment requirements and distribute maintenance outages so that system operations are optimized.

In 1994, electricity exports to the United States increased 53 per cent over 1993, reaching about 44 822 GWh, while imports decreased 65 per cent to only 938 GWh. Exports accounted for

9.2 per cent of Canada's total electricity generation in 1994, up from 5.8 per cent in 1993. Export revenue also increased significantly, by 55 per cent, from $858 million in 1993 to $1332 million in 1994, while import costs reduced from $85 million to $45 million.

Export increases in 1994 occurred mainly in Ontario, Quebec, and British Columbia due to improved water flows in these provinces. An increase in demand for electricity in New York and New England also contributed to the increase in exports.

Interruptible exports were the main type of electricity exports to the United States, accounting for 60 per cent of the total in 1994. Interruptible exports accounted for a much greater share of the total export revenue; 52 per cent compared with 48 per cent for firm exports.

Average firm and interruptible export revenues continued to rise in 1994 following a decline in 1992. Average firm revenues rose 4 per cent to 35.6 mills per kWh, while average interruptible export revenue rose 8 per cent to 25.7 mills per kWh.

Hydro generated electricity continued to be the main source of Canada's electricity exports, accounting for 68 per cent in 1994 compared to 77 per cent in 1993. Coal-fired exports rose from 14 per cent to 19 per cent, while the share of oil-fired exports increased slightly to 2 per cent. Nuclear power remained at 5 per cent in 1994. Exports from natural gas accounted for zero per cent of total exports compared to 2 per cent in 1993.

U.S. imports of Canadian electricity, as a percentage of total electrical energy demand in the United States, increased slightly from 1.0 per cent in 1993 to 1.5 per cent in 1994. However, U.S. dependence on Canadian exports was higher in certain regions. Exports to New England accounted for 9 per cent of the region's total electricity consumption in 1994. The corresponding ratio was 12 per cent for the Midwest and 8 per cent each for New York, and 2 per cent for the Pacific Northwest.

Electricity Trade and the Economy

The export of electricity is an important aspect of Canada's foreign trade. While total electricity export revenue accounted for only 0.6 per cent of total merchandise exports and 5.9 per cent of total energy exports in 1994, net electricity export revenue accounted for 5.0 per cent of Canada's balance of trade and 8.2 per cent of Canada's total energy trade balance in 1994. Canadian energy trade by fuel type during the period 1975-94 is reported in Table 8.11.

Interprovincial Trade

In Canada, provincial electric utilities trade electricity across provincial borders for the same reasons that trade occurs between Canada and the United States: to reduce costs, maximize profits, and mitigate emergencies. Electric utilities import electricity when imports are less expensive than their own production. Similarly, electric utilities export power when they can both meet domestic demand and maximize profits by marketing additional power to outside buyers.

Although Canadian interprovincial electricity trade has consistently been greater than that between Canada and the United States since 1975, it is mainly dominated by the Churchill Falls power contract signed between Newfoundland and Quebec. The Churchill Falls hydro project was owned by Newfoundland and Labrador Hydro, however, Hydro-Québec has a minority interest in the power plant. The Churchill Falls (Labrador) Corporation Limited operates the power plant, which began producing electricity in 1972. Under the power contract, about 90 per cent of the Churchill Falls

production is sold to Quebec. During the past 10 years, electrical energy sold to Quebec from Churchill Falls accounted for about 67 per cent of Canada's total interprovincial electricity trade.

Interprovincial electricity transfers during the period 1985-94 are summarized in Table 8.13. More information on exports and imports by province is provided in Figure 8.1 and Table A5 in Appendix A.

Tables and figures referred to in this chapter are on the following pages.

Tables & Figures

Table 8.1
Canada-U.S. Electricity Trade, 1960-1994

	Exports* (GWh) (1)	Exports as a Percentage of Total Generation (2)	Export Revenues ($million) (3)	Imports* (GWh) (4)	Imports as a Percentage of Total Disposal** (5)	Import Cost ($million) (6)	Net Exports (GWh) (7)=(1)-(4)	Net Exports $Million (8)=(3)-(6)
1960	5 496	4.8	14	357	0.3	1	5 139	13
1965	3 684	2.6	8	3 575	2.5	3	109	5
1970	5 631	2.8	32	3 245	1.6	9	2 386	23
1975	11 409	4.2	104	3 972	1.5	3	7 819	102
1980	28 224	7.7	773	168	0.1	3	28 056	791
1985	41 441	9.3	1 425	231	0.1	9	41 210	1 416
1987	45 359	9.4	1 211	536	0.1	12	44 823	1 199
1988	29 729	6.1	880	2 853	0.6	63	26 879	817
1989	18 462	3.8	661	8 747	1.9	292	9 715	369
1990	16 494	3.5	547	15 543	3.5	556	951	(9)
1991	19 828	4.1	558	1 905	0.4	71	17 923	487
1992	26 224	5.2	708	1 836	0.4	84	24 388	625
1993	29 364	5.8	858	2 692	0.6	85	26 672	773
1994	44 822	9.2	1 332	938	0.9	45	43 883	1 287

* Exports and imports prior to 1977 include service exchanges.
** Total disposal refers to total electricity available for domestic consumption.
Source: Electric Power Statistics, Volume II, Catalogue 57-202, Statistics Canada and Natural Resources Canada

Table 8.2
Provincial Shares of Canadian Electricity Exports, 1960-1994*

Year	New Brunswick	Quebec	Ontario	Manitoba	Sask.	British Columbia	Canada
1960	3.0	10.4	86.6	0.0	0.0	0.0	100.0
1965	6.4	1.3	84.0	0.0	0.0	8.3	100.0
1970	13.4	0.9	63.9	5.2	0.0	16.6	100.0
1975	14.2	8.0	42.5	10.3	0.0	25.0	100.0
1980	13.8	28.7	40.5	11.8	0.0	5.2	100.0
1985	14.8	23.1	22.5	13.6	0.3	25.7	100.0
1989	24.1	30.9	14.7	6.6	0.1	23.6	100.0
1990	25.4	30.9	4.5	11.7	0.3	27.2	100.0
1991	15.6	29.2	11.7	16.7	0.3	26.6	100.0
1992	6.6	33.7	7.8	23.1	0.3	28.5	100.0
1993	6.1	39.9	16.9	26.7	0.6	9.9	100.0
1994	5.2	37.6	28.3	19.6	0.1	9.2	100.0

* Excludes non-cash exchanges
Source: National Energy Board

Table 8.3
Firm and Interruptible Exports by Province, 1994*

	Firm	Interruptible	Firm	Interruptible
	(GWh)		(per cent)	
New Brunswick	814	1 524	35	65
Quebec	10 136	6 694	60	40
Ontario	258	12 406	2	98
Manitoba	4 872	3 981	55	45
Saskatchewan	0	21	0	100
British Columbia	1 721	2 390	42	58
Canada	**17 801**	**27 021**	**40**	**60**

* Exchanges are excluded
Source: National Energy Board

Table 8.4
Electricity Exports to the United States by Type, 1960-1994

	Quantity (GWh)		Revenue ($1000)		Quantity Share (%)		Revenue Share (%)	
	Firm*	Interruptible*	Firm	Interruptible	Firm	Interruptible	Firm	Interruptible
1960	1 040	4 456	4 328	10 023	19	81	30	70
1965	635	3 049	4 261	3 322	17	83	56	44
1970	984	4 648	6 828	25 309	18	82	21	79
1975	2 375	9 034	20 382	84 488	21	79	19	81
1980	7 232	20 992	156 731	636 760	26	74	20	80
1985	12 305	29 136	547 109	877 657	30	70	38	62
1990	8 701	7 794	346 513	200 147	53	47	63	37
1991	8 789	11 039	310 049	247 484	44	56	56	44
1992	12 168	14 056	397 184	311 070	46	54	56	44
1993	14 950	14 414	513 579	344 637	51	49	60	40
1994	17 801	27 021	634 501	694 122	40	60	48	52

* Electrical energy intended to be available at all times during the period of the agreement for its sale.

** Energy made available under an agreement that permits curtailment or interruption of delivery at the option of the supplier.

Source : National Energy Board

Table 8.5
Average Export Revenues, 1960-1994

Year	Firm	Interruptible	Total
		(mills/kWh)	
1960	4.2	2.3	2.6
1965	6.7	1.1	2.1
1970	6.9	5.5	5.7
1975	8.6	9.4	9.2
1980	21.7	30.3	28.1
1985	44.5	30.1	34.4
1990	39.8	25.7	33.1
1991	35.3	22.4	28.1
1992	32.6	22.1	27.0
1993	34.3	23.9	29.2
1994	35.6	25.7	29.7

Source: Calculated from Table 8.4

Table 8.6
Electricity Exports and Revenues by Province, 1992-1994*

	Quantity (GWh)			Revenue (million $)			Average Revenue (mills/kWh)		
	1993	1994	% Change	1993	1994	% Change	1993	1994	% Change
N.B.	1 778	2 338	31	80.55	87.51	9	45.2	37.4	17
Que.	11 707	16 835	44	365.10	463.71	27	28.3	27.5	-3
Ont.	4 964	12 664	155	131.62	351.39	167	26.5	27.7	5
Man.	7 824	8 853	13	204.96	280.83	37	26.1	31.7	21
Sask.	184	21	-89	3.45	.43	-88	18.8	20.5	9
B.C.	2 907	4 111	41	114.11	153.31	34	36.6	37.3	2
Canada	**29 364**	**44 822**	**53**	**858.22**	**1 337.18**	**56**	**29.2**	**29.8**	**2**

* Excludes non-cash exchanges.
Source: National Energy Board

Table 8.7
Average Export Revenues by Province, 1993 vs 1994

	Firm		Interruptible	
	1993	1994	1993	1994
		(mills/kWh)		
New Brunswick	50.8	54.2	31.8	28.8
Quebec	29.7	30.6	25.2	23.0
Ontario	25.9	20.9	26.5	27.9
Manitoba	39.1	42.5	15.7	18.5
Saskatchewan	-	-	18.8	20.1
British Columbia	35.3	40.0	39.0	31.8
Canada	**34.3**	**35.6**	**23.9**	**25.7**

Source: "Canada-U.S. Electricity Trade Report", Natural Resources Canada

Table 8.8
Generation Sources of Canadian Electricity Exports, 1975-1994

	Hydro	Imported Coal	Imported Oil	Domestic Coal/Oil	Nuclear	Natural Gas	Total
				(GWh)			
1975	5 724	4 838	494	353	0	-	11 409
1976	6 973	4 323	1 206	302	0	-	12 804
1977	7 926	8 514	2 961	555	0	-	19 957
1978	7 290	10 476	2 260	411	0	-	20 437
1979	15 213	11 587	3 354	128	177	-	30 458
1980	14 135	10 599	2 867	593	30	-	28 224
1981	21 182	10 901	1 940	665	42	-	34 730
1982	20 114	10 315	1 959	502	96	-	32 986
1983	21 978	11 704	1 201	519	1 856	-	37 258
1984	22 807	10 582	1 552	711	1 911	-	37 563
1985	28 836	8 245	1 157	956	2 247	-	41 441
1986	25 727	5 389	846	825	2 484	-	35 271
1987	34 065	7 575	1 270	408	2 041	-	45 359
1988	19 621	4 531	1 393	2 033	2 151	-	29 729
1989	9 054	1 452	1 089	2 214	2 032	2 621	18 462
1990	11 299	266	885	1 244	2 054	796	16 494
1991	14 415	1 546	610	697	2 172	388	19 828
1992	20 121	1 339	416	1 083	1 200	2 065	26 224
1993	22 978	2 934	263	1 088	1 501	601	29 364
1994	29 993	7 134	532	1 234	2 103	-	40 996

Source: Compiled from National Energy Board Statistics

Table 8.9
Energy Sources of Electricity Exports, 1994

	Natural Gas	Oil	Coal	Nuclear	Hydro	Other*	Total	Energy Exported
				(per cent)				(GWh)
New Brunswick	-	28	7	20	6	40	100	1 921
Quebec	-	-	-	-	100	-	100	16 831
Ontario	-	1	58	14	27	-	100	12 383
Manitoba	-	-	-	-	100	-	100	8 851
Saskatchewan	-	-	100	-	-	-	100	21
British Columbia	0	-	23	-	26	51	100	4 089
Canada	**0**	**2**	**19**	**5**	**68**	**7**	**100**	**44 096**

* Refers to U.S. electricity imports that are subsequently exported.
Source: Natural Resources Canada

Table 8.10
Exporting Provinces and Importing Markets, 1994*

Exporting Province	Importing Market	Quantity (MWh)	Value ($)
New Brunswick	Maine	1 998 604	70 162 940
Quebec	Maine	1 450	105 186
	Vermont	2 110 531	104 138 390
	New England (NEPOOL)**	6 972 110	166 320 962
	New York	7 750 299	193 146 076
Ontario	Vermont	300 497	6 606 868
	New York	5 221 133	149 178 327
	Massachusetts	14 685	349 798
	Michigan	6 910 227	189 069 912
	Minnesota	75 565	1 906 087
	Pennsylvania	141 341	4 261 167
Manitoba	Minnesota	7 777 187	259 158 808
	North Dakota	1 074 042	21 366 402
Saskatchewan	North Dakota	21 406	430 992
British Columbia	Washington	2 822 891	95 114 935
	Oregon	1 066 362	43 098 836
	Montana	67 315	2 284 975
	California	145 895	4 129 949
	Nevada	6 850	233 123
	Alaska	1 309	89 874
Canada	**United States**	**44 479 719**	**1 311 154 473**

* Excludes non-cash exchanges.
** The New England Power Pool (NEPOOL) coordinates electrical service to member utilities in New Hampshire, Maine, Vermont, Massachusetts, Conneticut, and Rhode Island.
Source: National Energy Board

Table 8.11
Canadian Energy Trade, 1975-1994

	Oil	Natural Gas	Coal	Electricity	Uranium	Total Energy
			($ million)			
1975						
Exports	3 684	1 092	483	104	133	5 496
Imports	3 508	8	643	13	12	4 184
Balance	**176**	**1 084**	**-160**	**91**	**121**	**1 312**
1980						
Exports	5 352	3 984	824	773	870	11 803
Imports	7 545	0	882	3	17	8 447
Balance	**-2 193**	**3 984**	**-58**	**770**	**853**	**3 356**
1985						
Exports	9 379	4 011	2 041	1 425	825	17 681
Imports	5 315	0	1 077	8	28	6 428
Balance	**4 064**	**4 011**	**964**	**1 417**	**797**	**11 253**
1990						
Exports	9 298	3 280	2 276	539	315	15 708
Imports	7 384	0	684	568	105	8 741
Balance	**1 914**	**3 280**	**1 592**	**-29**	**210**	**6 967**
1992						
Exports	9 801	4 608	1 884	708	497	17 498
Imports	5 887	50	647	84	114	6 775
Balance	**3 914**	**4 558**	**1 237**	**624**	**383**	**10 723**
1993						
Exports	10 936	5 778	2 070	858	499	20 140
Imports	6 399	47	484	85	127	7 142
Balance	**4 537**	**5 731**	**1 586**	**773**	**372**	**12 998**
1994						
Exports	11 587	6 717	2 289	1 273	621	22 487
Imports	6 654	85	523	44	182	7 486
Balance	**4 933**	**6 632**	**1 766**	**1 229**	**439**	**15 001**

Source: Statistics Canada, Exports by Commodities (65-004) and Imports by Commodities (65-007)

Table 8.12
Annual Canadian Interprovincial Electricity Trade, 1960-1994

Year	Total Canadian Generation (GWh)	Delivered to other Provinces (GWh)		Percentage of Interprovincial Transfers to Total Generation	
		With Churchill Falls*	Without Churchill Falls	With Churchill Falls	Without Churchill Falls
1960	114 378	7 108	7 108	6.2	6.2
1965	144 274	6 230	6 230	4.3	4.3
1970	204 723	8 137	8 137	4.0	4.0
1975	273 392	49 198	19 684	18.0	7.2
1980	367 306	52 709	14 965	14.4	4.1
1985	446 413	51 663	19 917	11.6	4.5
1989	482 158	36 176	11 809	7.5	2.4
1990	465 967	37 499	11 335	8.0	2.4
1991	489 227	38 530	12 164	7.9	2.5
1992	501 523	41 586	15 601	8.3	3.1
1993	511 769	40 063	10 122	7.8	2.0
1994	533 508	39 558	12 112	7.4	2.3

* The Churchill Falls project was completed in 1974 (the initial operation started in 1971). Over 90% of the energy it produces flows into Quebec under a contract that terminates in the year 2041.

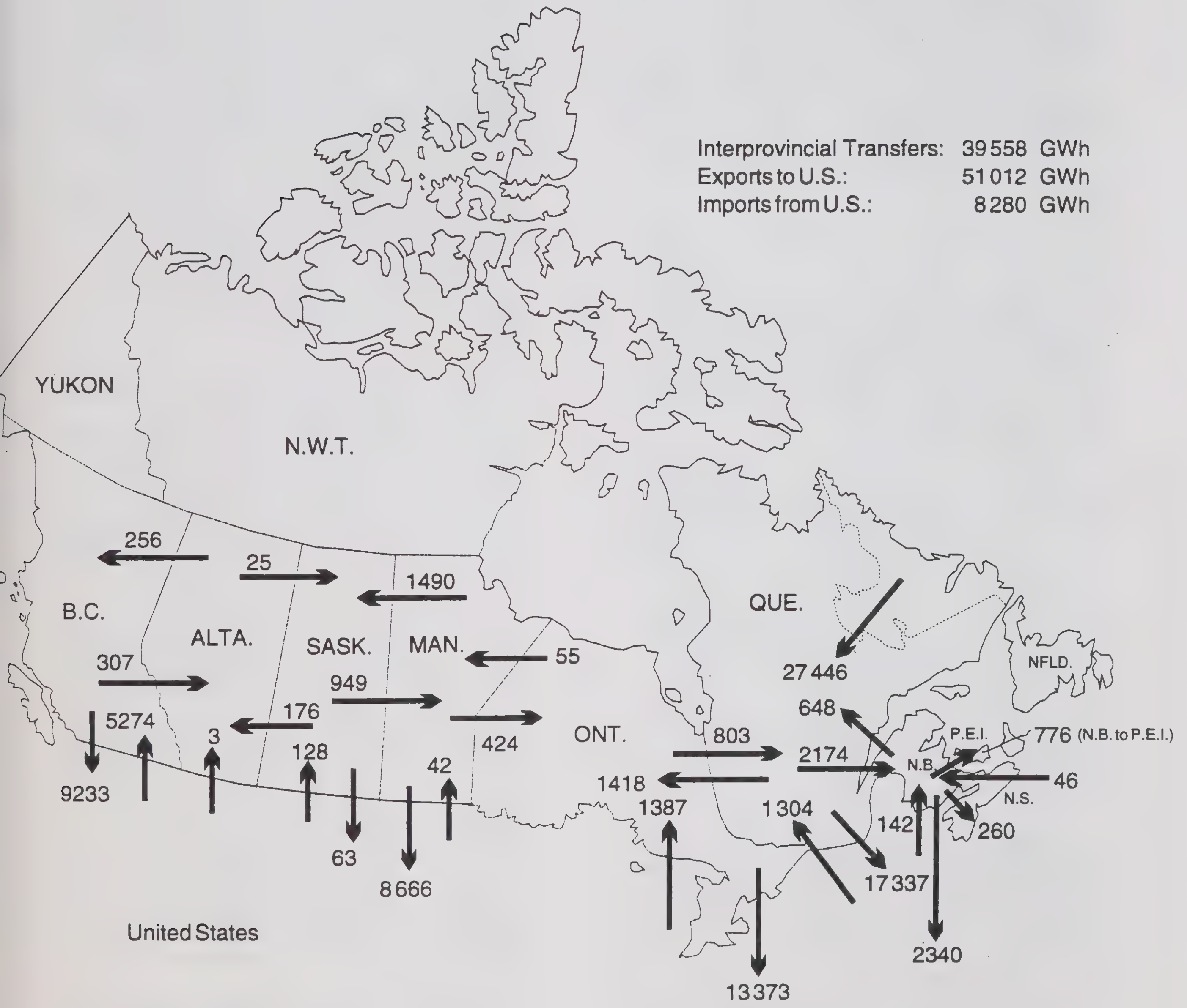
Source: Natural Resources Canada

Table 8.13
Interprovincial Electricity Trade by Destination, 1985-1994

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
					(GWh)					
Nfld. to Que.	31 836	30 695	30 393	30 727	24 367	26 164	26 366	25 985	29 942	27 446
N.S to N.B.	190	71	82	166	341	116	50	67	42	46
N.B. to N.S.	360	620	659	186	441	365	444	253	248	260
N. B. to P.E.I.	585	610	483	486	622	672	690	738	747	776
N.B. to Que.	2	0	20	309	951	1 116	1 408	3 354	37	648
Que. to N. B.	5 951	7 204	6 840	2 690	1 966	2 659	3 383	3 858	1 467	2 174
Que. to Ont.	8 685	7 292	5 942	2 289	1 032	690	729	651	1 019	1 418
Ont. to Que.	106	17	15	43	80	134	109	187	540	803
Ont. to Man.	0	5	3	22	11	6	0	14	15	55
Man. to Ont.	959	735	1 050	538	1 303	1 636	1 482	1 552	878	424
Man. to Sask.	1 530	1 211	1 262	1 370	1 171	1 058	1 152	1 561	1 362	1 490
Sask. to Man.	1 240	1 076	1 220	1 109	1 115	1 047	975	951	909	949
Sask. to Alta.	0	0	0	0	15	39	23	132	421	176
Alta. to Sask.	0	0	0	0	42	94	116	23	26	25
Alta. to B.C.	182	617	710	1 218	2477	1 242	948	1 993	2 062	2 561
B.C. to Alta.	37	553	521	364	242	461	655	267	348	307
Total	**51 663**	**50 706**	**49201**	**41 517**	**36 176**	**37 499**	**38 530**	**41 586**	**40 063**	**39 558**

Source: National Energy Board

Figure 8.1 Electricity Trade, 1994 (GWh)



* *Includes non-cash exchanges*

Transmission

Transmission Circuit Length

The electric power system in Canada consists of three interrelated functions: the generating system which produces the power; the transmission network which conducts the flow of power from the point of generation to the point of distribution; and the distribution system which delivers the power to consumers. In most provinces, all three of these interrelated functions are provided by one or a few major electric utilities.

The electrical transmission network in Canada has evolved from a simple system designed to serve customers at the local level into a highly complex interconnected system. In the early years of the 20th century, relatively small generating plants were situated close to the loads which they served, with power transmitted at low voltages under 60-kV.

Fast growth in electricity demand throughout the early 20th century brought forth successively larger power plants that were constructed farther away from load centres and nearer to abundant water resources. Transmission systems were used to distribute power to the geographically dispersed load areas. The integrated electric power system, coupled with the growth in interconnection of previously isolated power networks, led to the development of a new generation of higher voltage transmission in the range of 100 to 230-kV.

After World War II, in response to rapid electrification and installation of larger hydro and thermal generating stations, much higher voltages of transmission lines, such as 345-kV, 500-kV, 735-kV, and ±450(DC) were introduced into commercial operation.

Total circuit length of electrical transmission in Canada for lines rated at 50-kV and above, increased by 1845 km in 1994, much less than the 724 km in 1993. The total length of Canadian bulk transmission is now 157 173 km, with the largest share (31 per cent) being in the 100-kV to 149-kV range. Another 25 per cent is in the 200-kV to 299-kV range, while 21 per cent is between 50-kV and 99-kV (Table 9.1). Newfoundland and Quebec are the only two provinces with transmission lines over 600-kV. Newfoundland has three 735-kV lines wheeling power from its Churchill Falls hydro station in Labrador to Quebec City and Montreal, and Quebec has six 735-kV lines and one ±450-kV high-voltage direct current (HVDC) line delivering power from four hydro stations in the James Bay region to Montreal and the United States. Quebec also has a 765-kV line used mainly for export purposes, which delivers power from Chateauguay to the State of New York.

In 1994, transmission line additions within the provinces were found mainly in Quebec, Ontario, and British Columbia. Hydro-Québec increased its 735-kV line by 965 km, linking Chissibi to Jacques Cartier. Ontario Hydro increased its 500-kV line by 111 km from Lennox to Bonmanville. B. C. Hydro completed its 500-kV line from Williston to Kelly Lake in 1994 and added 330 km to its system. TransAlta Utilities Corporation completed its 240-kV lines by 443 km, linking Sundance to Petrolia and Dome, and Keephills to Benalto.

Presently, there are 11 in-province transmission lines under construction ranging from 69-kV to 735-kV, with a total circuit length of only 609 km. Hydro-Québec is building a 735-kV line linking Des Cantons to Levis, with a total circuit length of 181 km. Hydro-Québec is also building one 315-kV line in the James Bay area, linking LG-2A to Radisson, and a 69-kV line from Lac Robertson to La Tabatière.

Ontario Hydro is in the process of adding three more 230-kV lines. One will connect the Fraserville with Dobbin and the other will link Ansonville and Teck. Newfoundland & Labrador Hydro is building 4x138 kV lines and

1x69 kV lines, with a total circuit length of 236 km.

Interprovincial Transmission

To facilitate energy exchanges and enhance the reliability of electrical systems operation, there are now 36 major provincial inter-connections, with a total transfer capability of about 10 145 MW (Table 9.2). No provincial interconnection was added in 1994.

Due to slow economic growth, no provincial interconnections are planned for the time being.

International Transmission

Interconnections play a major role in modern power systems. Most Canadian utilities have both east-west and north-south lines that allow exchanges of power and energy. No international interconnection was completed in 1994.

There are now over 100 international transmission lines in place to provide for Canada's international electricity trade. Although most of these lines are quite small, there are 37 bulk power interties rated at 69-kV or higher, with a total power transfer capability of 18 900 MW (Table 9.3).

B.C. Hydro is in the process of planning two 230-kV international trans-mission lines. The new lines will increase B.C. Hydro's total firm power transfer capability by about 700 MW. The lines are expected to be in service by 1999 and 2003, respectively. New Brunswick Power is also planning to build a 345-kV line from Lepreau to Orrington of Maine. The transfer capability is estimated at 600 MW and is expected to be in service by 1998 (Table 9.4).

Long-Distance Transmission

Canada is a world leader in long-distance electric power transmission, in both extra-high-voltage (EHV) alternating current and HVDC. A major influence on the development of Canada's expertise in these areas has been the country's abundant water power resources. Early in the century, pioneering efforts in high-voltage transmission resulted in the initial development of hydroelectric power at Niagara Falls to supply the growing needs of communities in southern Ontario. In Quebec, the first 50-kV transmission lines were constructed to bring power from Shawinigan to Montreal.

After the harnessing of major hydroelectric sites close to load centres, it became necessary to develop remote hydroelectric sources in several provinces and to integrate these sources into the power system over long-distance EHV and HVDC transmission lines. In 1965, Hydro-Québec installed the world's first 735-kV class transmission system. This system now extends over 1100 km from the Churchill Falls development in Labrador to Montreal. A comparable system of about the same distance extends from the James Bay development to Quebec's load centres.
In Manitoba, pioneering work was done under federal financial assistance to develop the ±450-kV HVDC system which now brings hydroelectric power from the Nelson River generating stations to customers in southern Manitoba. Recently, Hydro-Québec built a ±450-kV HVDC line delivering power from La Grande 2 station at Radisson to the United States. Ontario and British Columbia also have extensive EHV systems in the 500-kV class (Figure 9.1).

Such advances in Canadian transmission techniques have provided not only for long-distance bulk transmission, but also for extensive interconnections between neighbouring provinces and between Canada and the United States (Figure 9.2).

Reliability of Electric Service

Reliability of electric service has always been of prime importance to the electrical system. The reliability of supply is reflected in terms of frequency and duration of interruptions (outages) to the customer. The reliability of an electricity supply system, particularly the transmission and distribution segments of the system, is determined by a variety of factors, such as scheduled interruptions, loss of supply, tree contact, lightning, defective equipment, adverse weather, adverse environment, human elements, and other interference. Canada with its vast territory, long and severe winters, and its large hydro-electric plants which are often located far from population centres, is likely to be at a disadvantage compared to countries with smaller geographic areas and greater population density.

In Canada, the most commonly used indices to measure the reliability of electric service are the *System Average Interruption Frequency Index (SAIFI)*, the *System Average Interruption Duration Index (SAIDI)*, and the Customer *Average Interruption Duration Index (CAIDI)*. The SAIDI is the product of SAIFI and CAIDI.

Figure 9.3 provides a comparison of the frequency of supply interruptions per customer per year for 14 major Canadian electricity suppliers in 1994. There is considerable variation in performance across Canada, for example, the Newfoundland and Labrador Hydro shows an interruption frequency seventeen times higher than the TransAlta Utilities figure, and although Ontario Hydro serves electricity in a vast territory under severe weather, its reliability is one of the best in Canada. Hydro-Québec, B.C. Hydro, and Manitoba Hydro are predominately hydroelectric systems, however, the interruption frequency of Hydro-Québec's system is 2.8 times higher than that of
B.C. Hydro and about 3.3 times higher than the Manitoba Hydro figure.

The duration of interruptions is reflected, in part, by how quickly the various electric authorities correct faults in the system. As was pointed out earlier, many factors will determine the duration of interruptions. Some of these factors such as the severity of storms, fires, and floods will be out of the electricity suppliers' control. As a result, considerable variation in the duration of interruption may be expected from year to year.

Figure 9.4 presents the duration of interruptions by customer for 14 major Canadian electric utilities. As in the case of interruption frequency, the duration of interruptions in Canadian electrical systems varies considerably, ranging from 32 minutes for Edmonton Power to more than four hours for Newfoundland Light and Power. Edmonton Power's much shorter interruption duration is partially due to the fact that it is a municipal utility serving electricity in a much smaller area with a greater population density.

Although Hydro-Québec has a much higher frequency of outages when compared to other Canadian electrical systems, the short duration of its outages in 1994 reflects a quick response time to faults in the system.

As indicated in Figure 9.4, the average customer outage duration in Canada was 80 minutes in 1994, down from 110 minutes in 1993.

The product of average interruption frequency and customer average interruption duration provides an estimate of system average interruptible duration per year. The comparisons summarized in Figure 9.5 indicate that there are significant differences in system performance by province. For instance, the system average interruption time per year for Edmonton Power was only 37 minutes,

compared with 1422 minutes for Newfoundland Light and Power.

On average the Canadian systems were relatively higher in interruption frequency and faster in dealing with faults in transmission and distribution. Therefore the system average interruptible duration per year was quite comparable with other countries, about 203 minutes, as reported in Figure 9.5.

Tables and figures referred to in this chapter are on the following pages.

Tables & Figures

Table 9.1
Transmission Circuit Length in Canada, 1994

	50-99 kV	100-149 kV	150-199 kV	200-299 kV	300-399 kV	400-599 kV	600 kV and up	Total
				(km)				
Nfld.	2 612	1 985	-	2 005	-	-	612	7 214
P.E.I.	390	193	-	-	-	-	-	583
N.S.	2 027	1 703	-	1 236	674	-	-	5 640
N.B.	2 716	2 048	-	629	1 189	-	-	6 582
Quebec	4 150	7 762	2 266	3 810	7 306	1 560	10 920	37 774
Ontario	247	12 318	-	13 971	6	3 148	-	29 726
Manitoba	6 756	4 266	-	4 503	-	2 042	-	17 567
Sask.	4 849	4 534	-	3 250	-	-	-	12 633
Alberta	3 481	9 216	-	5 926	-	215	-	18 838
B.C.	4 996	4 702	316	3 430	403	5 674	-	19 521
Yukon	65	497	-	-	-	-	-	562
N.W.T.	100	-	-	-	-	-	-	100
Canada	**32 389**	**49 224**	**2 582**	**38 760**	**9 578**	**12 675**	**11 532**	**156 740**
	(21%)	(31%)	(2%)	(25%)	(6%)	(8%)	(7%)	(100%)

Source: Statistics Canada Publication 57-202 and Natural Resources Canada

Table 9.2
Provincial Interconnections at Year-End, 1994

Connection	Voltage	Design Capability*
	(kV)	(MW)
British Columbia - Alberta	1 x 500	800
	1 x 138	110
Alberta - Saskatchewan	1 x 230	150
Saskatchewan - Manitoba	3 x 230	400
	2 x 110	100
Manitoba - Ontario	2 x 230	260
	1 x 115	
Ontario - Quebec	4 x 230	1 300
	7 x 120	
Quebec - Newfoundland	3 x 735	5 225
Quebec - New Brunswick	2 x $\pm$80(DC)	700
	2 x 345	
	2 x 230	300
New Brunswick - Nova Scotia	2 x 138	600
	1 x 345	
New Brunswick - P.E.I.	2 x 138	200

* Actual transfer capabiity in practice will be different from design capability.
Source: Natural Resources Canada

Table 9.3
Major Interconnections Between Canada and the United States, 1994*

Province	State	Voltage (kV)	Design Capability*** (MW)
New Brunswick	Maine	1 x 345	600
		1 x 138	60
		5 x 69	155
Quebec	New York	1 x 765	2 300
	New York	2 x 120	300
	Vermont	3 x 120	375
	New Hampshire	±450(DC)	2000
Ontario**	New York	1 x 230	470
		1 x 230	400
		2 x 230	600
		2 x 345	2 300
		2 x 69	132
		2 x 115	200
	Michigan	1 x 230	535
		1 x 230	515
		2 x 345	1 470
	Minnesota	1 x 120	35
Manitoba	North Dakota	1 x 230	150
	Minnesota	1 x 230	175
	Minnesota	1 x 500	1 000
Saskatchewan	North Dakota	1 x 230	150
British Columbia**	Washington	1 x 230	300
		1 x 230	400
		2 x 500	4 300

* 35 MW capacity or over.
** The transfer capability of several lines may not be equal to the mathematical sum of the individual transfer capabilities of the same lines.
*** Actual transfer capability in practice will be different from design capability.

Source: Natural Resources Canada

Table 9.4
Planned International Interconnections

Province/State	Voltage (kV)	Estimated Power transfer Capability (MW)	Completion Date	Status
N.B. - Maine	345	600	1998	Proposed
B.C. -Washington	230	350	1999	Proposed
B.C. -Washington	230	350	2003	Proposed

Source: Canadian Electric Utilities

Figure 9.1 Canada's Major Long-Distance Transmission Systems, 1994

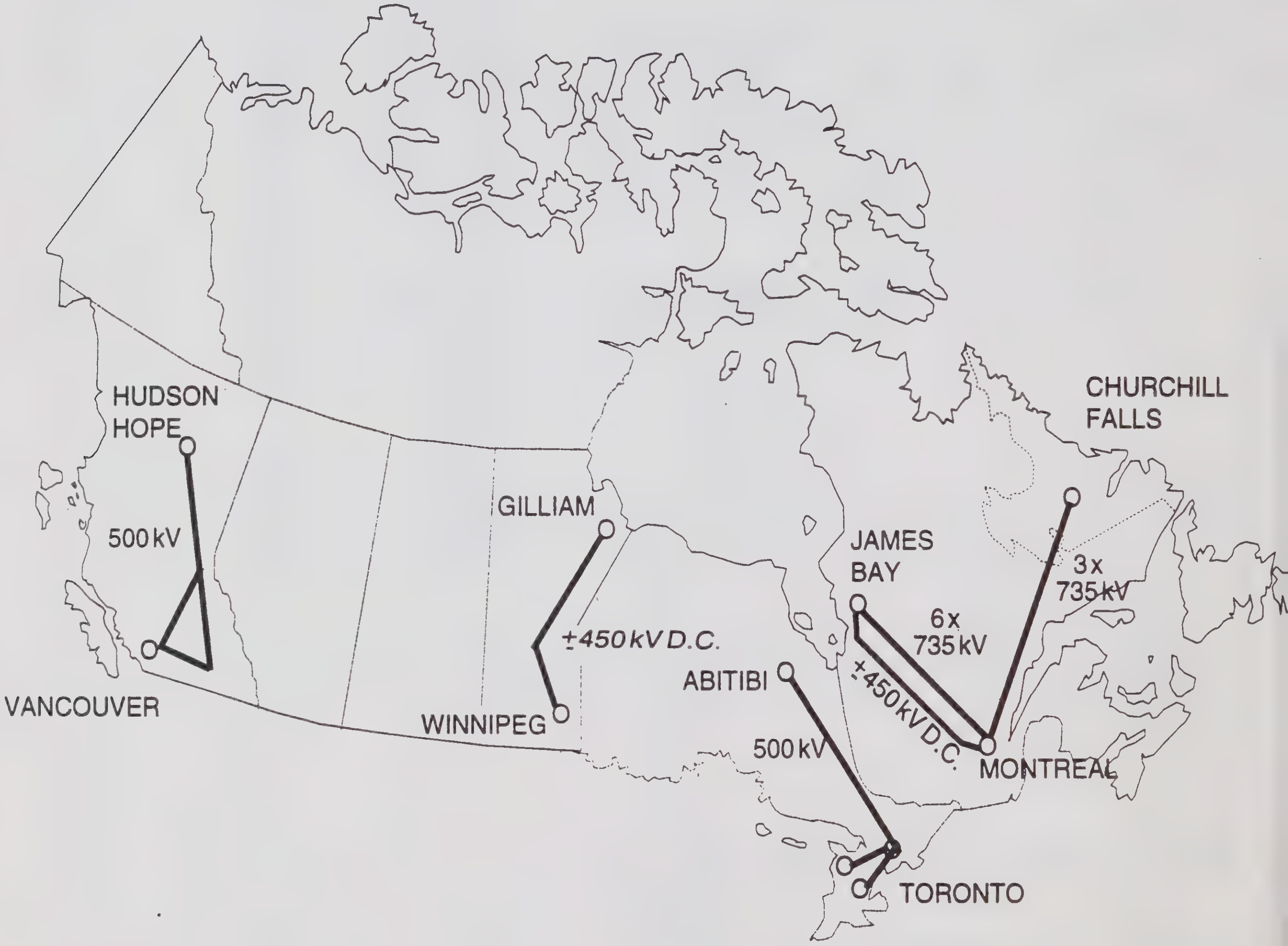


Figure 9.2 Major Provincial and Interprovincial Interconnections, 1994

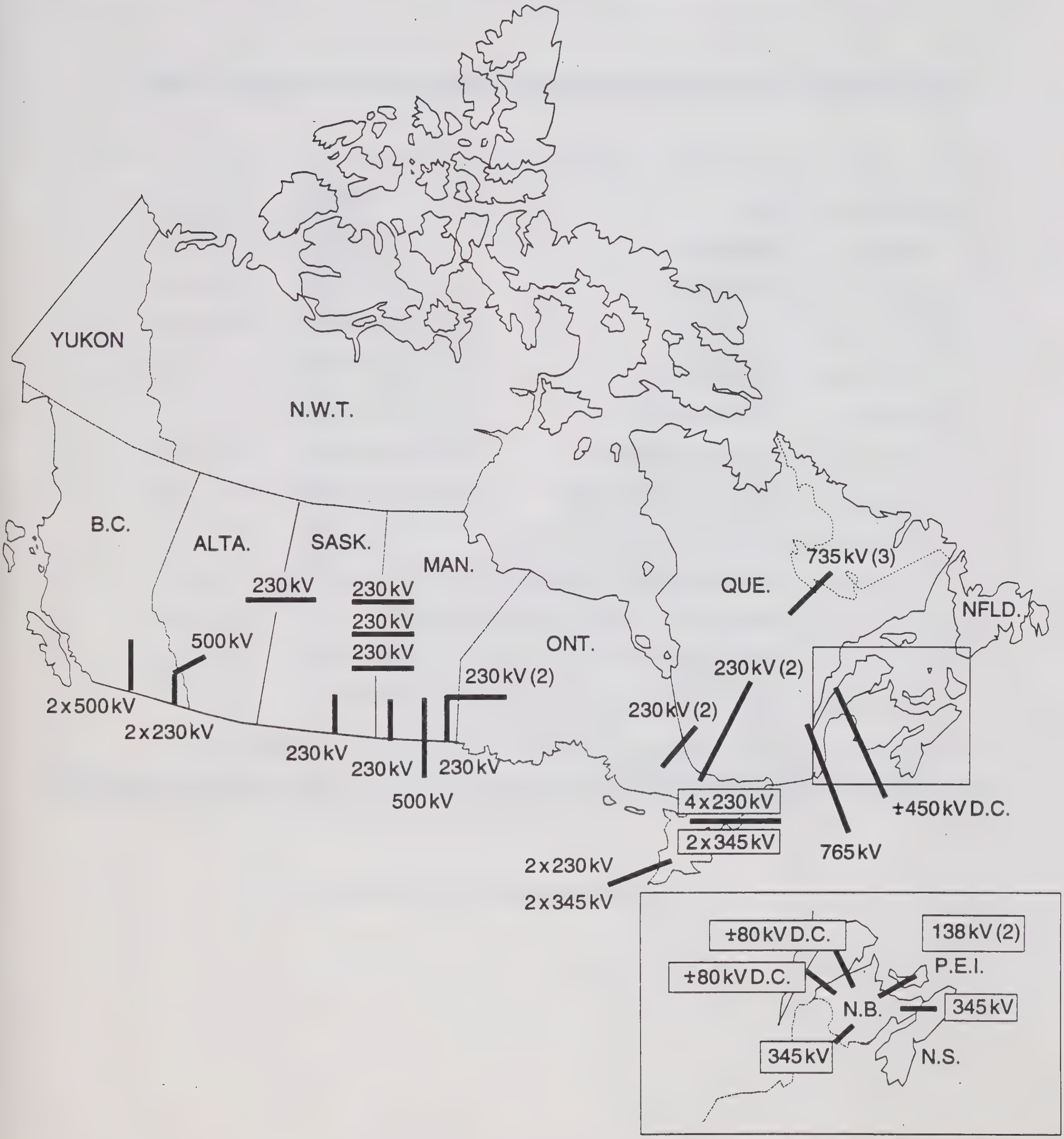


Figure 9.3 System Average Interruption Frequency in Canada, 1994

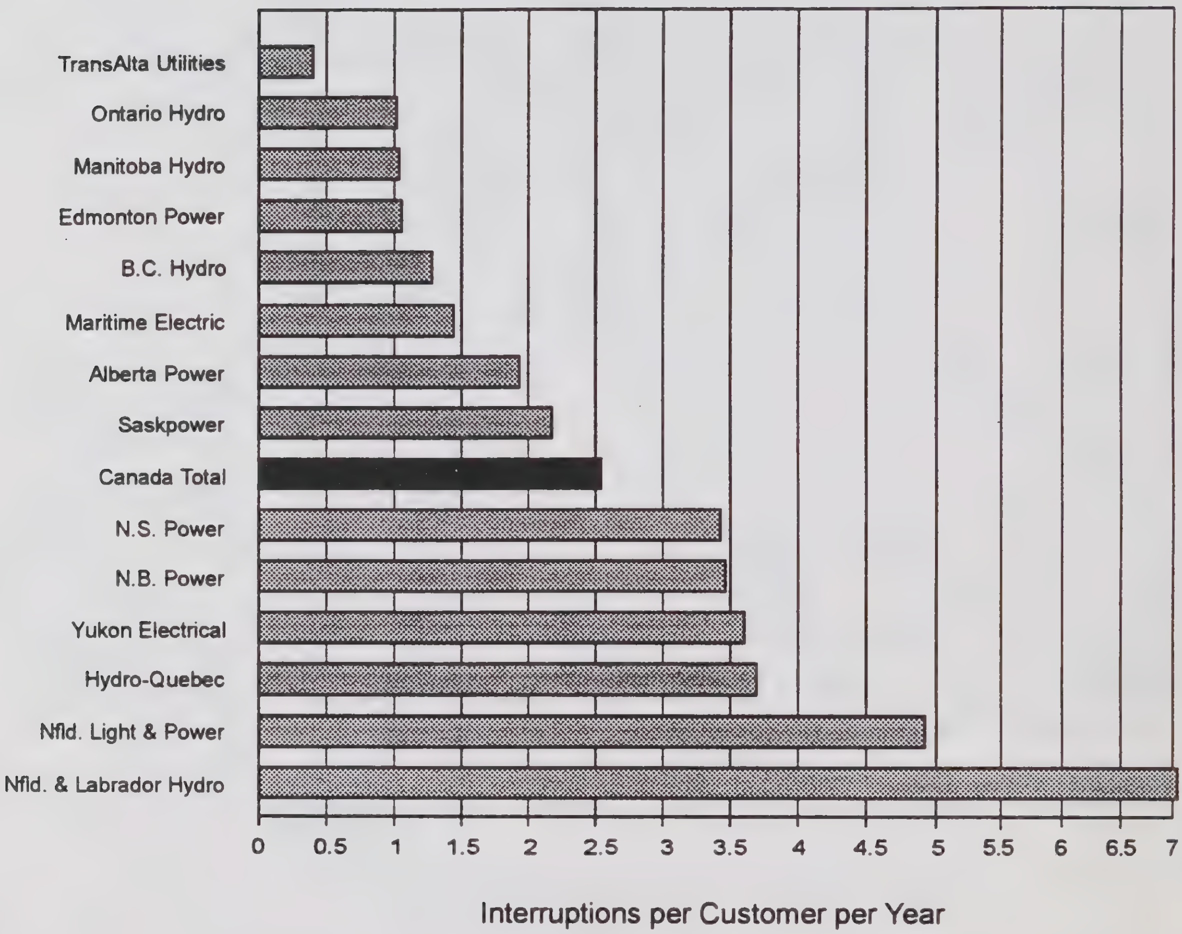


Figure 9.4 Customer Average Interruptible Duration in Canada, 1994

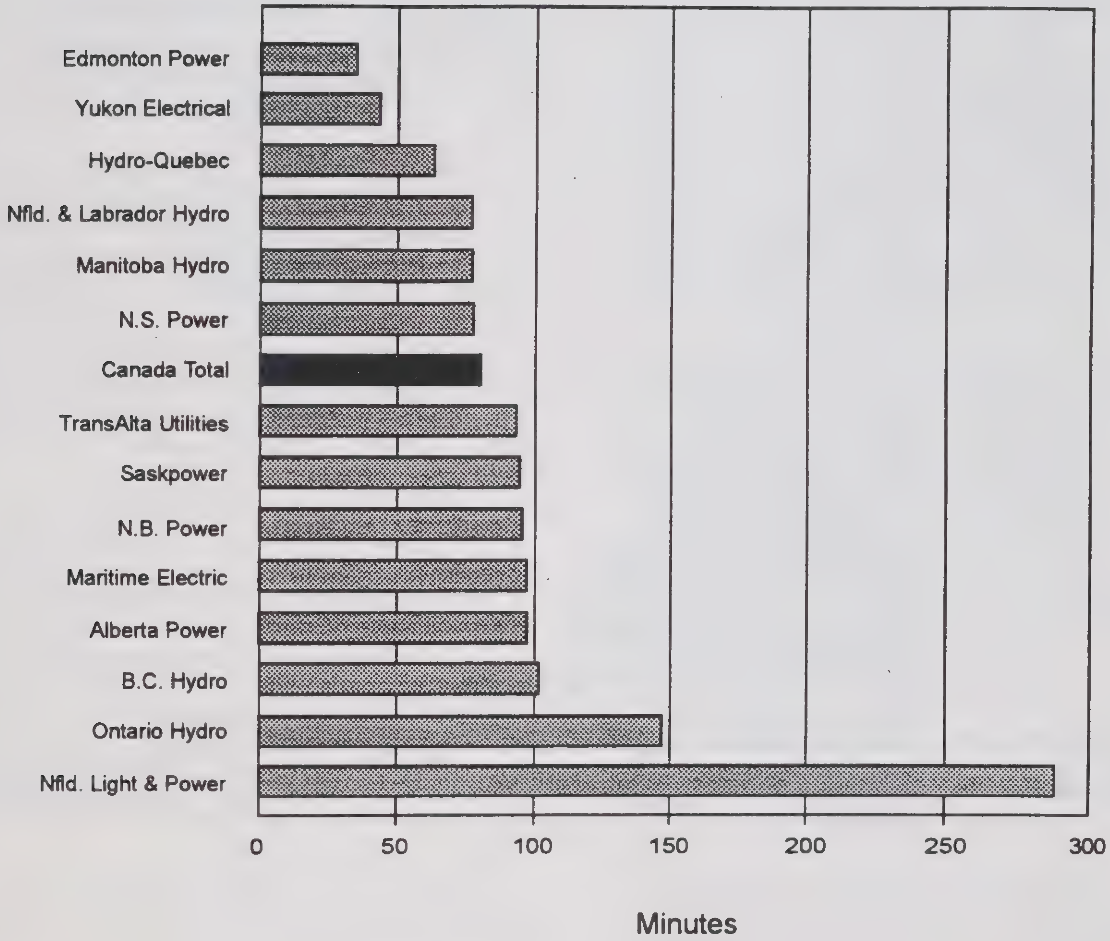
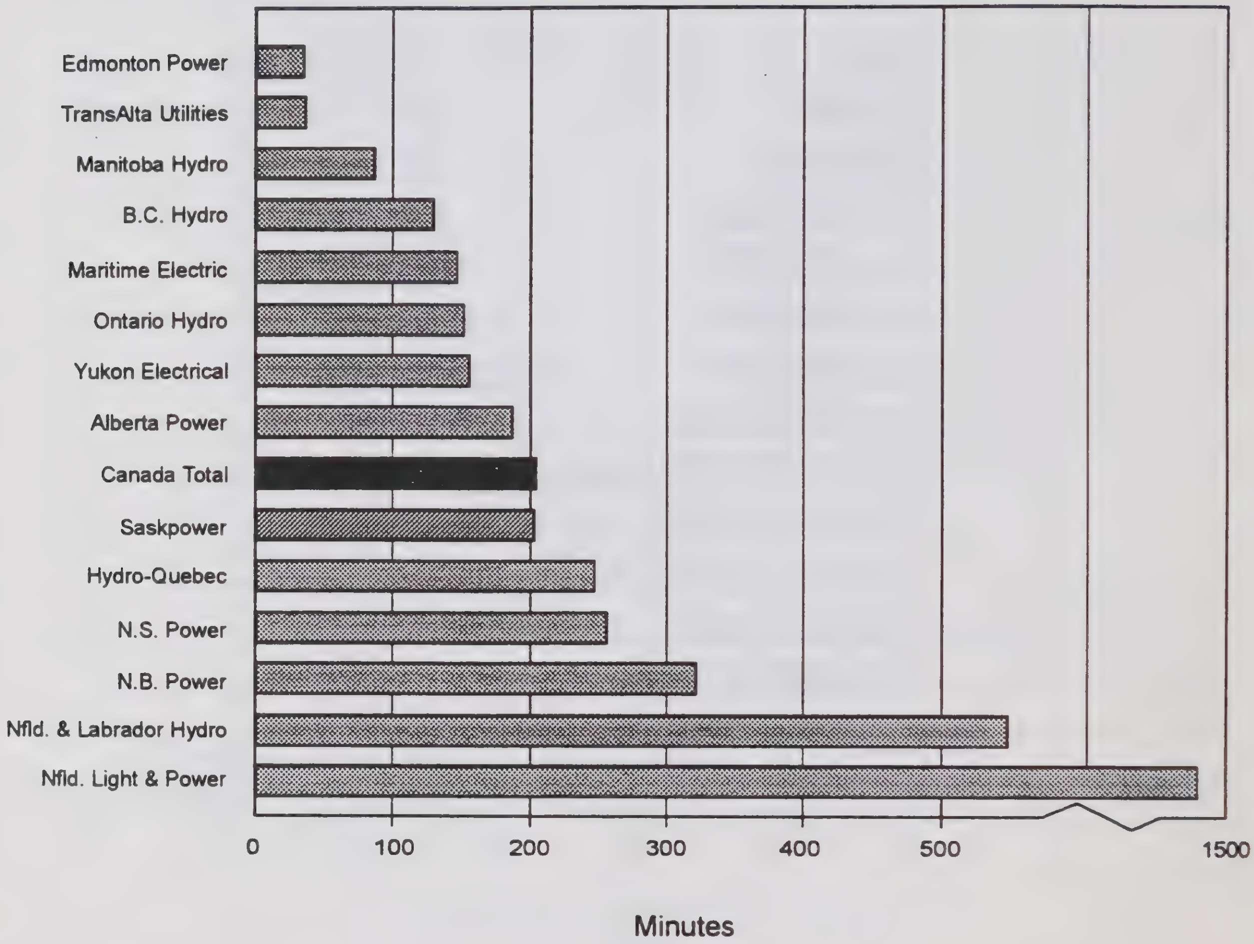


Figure 9.5 System Average Interruptible Duration in Canada, 1994



Electric Utility Investment and Financing

Capital Investment

The electric power industry is one of the most capital intensive industries in our economy. Between 1961 and 1994, the average capital-output ratio for the industry was 8.3. This means that in order to generate one dollar's worth of electricity, more than eight dollars must be invested in the electric power industry. This capital-output ratio is very high, compared with 1.1 for total manufacturing industries, and 1.6 for the economy as a whole.

The most capital intensive type of electrical generation is nuclear. It is estimated that the capital cost of nuclear generation, including depreciation, the debt guarantee fee and financing charges, accounts for about 67 per cent of the total cost. The fuel cost accounts for only 10 per cent, and operation and maintenance for 23 per cent. Because of such a cost structure, nuclear energy is inflation proof over its 40-year life-service.

Every year, electric utilities invest in new facilities or upgrade old facilities to meet customer needs. From 1971 to 1994, electric utilities total capital investments increased from about $1.8 billion to $7.2 billion, with an average annual growth rate of 6.4 per cent. If the average annual inflation over this period (5.8%) is removed, the real annual growth rate is 0.6%. Table 10.1 illustrates the capital- intensive nature of electricity generation and its importance in the Canadian economy.

Table 10.2 summarizes capital expenditures in the energy sector. During the period 1972-94, the electric power industry had the largest investment share in the energy sector, with the exceptions of 1984, 1985 and 1994, when petroleum and natural gas exploration and production had the largest share.

In 1994, the electric power industry's investment share was 33 per cent of the total for the energy sector. This is a substantial decrease from 53 per cent in 1992 and is the lowest in the past five years, indicating that the electric power industry may be returning to the low investment period of the 1980s because of slow growth of demand and surplus capacity (Table 10.1).

Of the total $7.2 billion capital investment in 1994, about 41 per cent was invested in generation, 24 per cent in trans-mission, 20 per cent in distribution, and 15 per cent in others (Table 10.3). This represents a fairly large investment in generation for the period, since a traditional rule-of-thumb states that capital investment in generation normally accounts for 50 per cent of total investment in the industry. Figure 10.1 shows electric utility capital investment by function in 1994.

Table 10.4 reports the capital investment for 15 major electric utilities in 1993 and 1994. With the exceptions of Newfoundland Power, Maritime Electric and TransAlta Utilities Corporation, all major utilities reduced their capital investment in 1994. Hydro-Québec was the largest money spender, accounting for 46 per cent of total utility capital investment in 1994, most of which was related to the on-going construction of the James Bay Phase II hydroelectric projects.

Capital Financing

To build a power project, an electric utility normally uses its reserve funds to finance a portion of the construction costs (self-financing), with the larger portion of the costs usually financed by international and domestic debt borrowing (debt-financing) and bond and/or stock issues (equity-financing). Electric utilities regularly have to pay a fixed interest charge on debt- financing, while the payments on equity-financing, especially stock issues, are determined by the operation of the utility.

Canada's electric utilities rely heavily on foreign sources to finance their capital investment because of a relatively small financial market within the country. However, the degree of dependence on foreign financing has been reduced substantially since 1986. Some major electric utilities have tried to finance their power projects mainly from domestic financial markets in order to avoid foreign exchange losses. In 1985, foreign financial sources accounted for 52 per cent of the existing total long-term debt financing. This percentage was reduced to 46 in 1986, 43 in 1987, 40 in 1988, and 35 in 1990. As of December 31, 1994, the total outstanding long-term debt of major electric utilities in Canada was about $90 billion. Of this total, about 63 per cent (or $57 billion) was borrowed on the domestic market, and 37 per cent (or $33 billion) on international markets. Of the $33 billion borrowed internationally, it is estimated that 85 per cent (or $28 billion) was raised in the United States; 4.5 per cent (or $1.4 billion) in the United Kingdom; 3.9 per cent (or $1.3 billion) in Germany; 3.3 per cent (or $1.1 billion) in Japan; and 2.7 per cent (or $890 million) in Switzerland (Table 10.5).

In Canada and the United States, publicly owned electric utilities depend mainly on debt-financing. Investor-owned utilities, on the other hand, rely much more on equity-financing. Table 10.6 indicates that in 1993, Canadian publicly owned electric utilities had debt ratios ranging from 68 per cent to 93 per cent. With the exception of Manitoba Hydro, all publicly owned utilities have strong financial positions. The debt ratios for investor-owned utilities ranged from 38 per cent to 61 per cent, indicating they are also financially sound.

High debt ratios, similar to those of Canadian publicly owned utilities, were also common among government-owned utilities in the United States. As Table 10.6 indicates, the Power Authority of the State of New York, the Tennessee Valley Authority, and the Bonneville Power Administration had debt ratios of 74, 88 and 100 per cent respectively. The selected American investor-owned utilities had debt ratios ranging from 39 per cent to 56 per cent in 1991. In general, the financial position of American investor-owned utilities is not as good as that of their Canadian counterparts.

Tables and figures referred to in this chapter are on the following pages.

Tables & Figures

Table 10.1
Electric Utility Capital Investment, 1971-1994

	Investment in electric power industry ($ million)	Utility investment as a percentage of total energy investment	Utility investment as a percentage of total investment in the economy	Utility investment as a percentage of GDP
1971	1 747	52	8	1.8
1972	1 754	49	7	1.6
1973	2 244	53	8	1.8
1974	2 753	53	8	1.8
1975	3 957	58	9	2.3
1976	4 229	55	9	2.1
1977	4 884	56	10	2.2
1978	5 936	58	11	2.5
1979	6 364	53	10	2.3
1980	6 109	42	8	2.0
1981	7 319	40	9	2.1
1982	8 408	39	10	2.2
1983	7 770	42	10	1.9
1984	6 340	37	8	1.4
1985	5 727	34	6	1.2
1986	5 618	41	6	1.1
1987	5 946	45	6	1.1
1988	6 971	44	7	1.2
1989	8 458	50	6	1.3
1990	10 291	52	8	1.5
1991	11 826	50	9	1.7
1992	10 917	53	9	1.6
1993	8 723	43	7	1.2
1994	7 227	33	6	1.0

Source: Natural Resources Canada

Table 10.2
Investment in Energy-Related Industries, 1972-1994

Year	Petroleum and Natural Gas: Exploration and Production	Petroleum and Natural Gas: Refining and Marketing	Petroleum and Natural Gas: Natural Gas Processing Plants & Distribution	Pipelines	Electric Power	Coal Mines & Products	Uranium Mines	Drilling Contractors	Total
	(millions of dollars)								
1972	666	351	272	447	1 754	42	11	24	3 567
1975	1 390	595	341	362	3 957	123	30	27	6 825
1980	5 745	502	698	602	6 109	306	277	198	14 437
1985	8 187	681	942	665	5 727	475	160	80	16 917
1986	5 401	723	782	587	5 618	434	144	30	13 724
1987	4 415	1 052	746	503	5 946	338	113	13	13 126
1988	5 590	1 135	875	829	6 971	345	139	17	15 901
1989	4 310	1 433	997	1 183	8 458	1	105	14	16 811
1990	4 751	1 382	1 112	1 817	10 291	8	138	12	19 841
1991	6 084	1 129	1 537	2 546	11 826	398	45	41	23 606
1992	4 607	722	1 506	2 432	10 917	177	80	34	20 476
1993	7 309	464	1 469	2 047	8 723	290	115	43	20 460
1994	9 900	507	1 548	2 323	7 227	230	-	97	21 832

Source: Natural Resources Canada

Table 10.3
Capital Investment by Function, 1972-1994

Year	Generation	Transmission	Distribution	Other	Total
	(millions of current dollars)				
1972	1 020	432	229	73	1 754
1975	2 460	616	547	334	3 957
1980	3 580	1 114	703	712	6 109
1985	2 941	836	1 008	942	5 727
1986	3 214	815	989	600	5 618
1987	2 774	1 200	1 039	933	5 946
1988	3 137	1 812	1 115	907	6 971
1989	4 313	2 115	1 269	761	8 458
1990	6 147	2 074	1 235	835	10 291
1991	6 340	2 551	1 398	1 417	11 826
1992	5 676	2 402	1 310	1 529	10 917
1993	4 440	1 363	1 956	964	8 723
1994	2 935	1 722	1 443	1 127	7 227

Source: Natural Resources Canada

Table 10.4
Capital Investment by Major Electric Utility

	1993	1994	Year-Over-Year Change
	(millions of current dollars)		
Newfoundland and Labrador Hydro	25	28	- 3
Newfoundland Light & Power	33	34	1
Maritime Electric Co. Ltd.	12	14	2
Nova Scotia Power	132	93	- 39
NB Power	530	148	- 382
Hydro-Québec	4 030	3 298	- 732
Ontario Hydro	2 288	1 379	- 909
Manitoba Hydro	300	260	- 40
Saskatchewan Power	229	201	- 28
Alberta Power	102	93	- 9
Edmonton Power	215	95	- 120
TransAlta Utilities	169	199	30
B.C. Hydro	440	415	- 25
Yukon Energy Corporation	11	8	- 3
Northwest Territories Power Corporation	19	17	- 2
Canada	**8 537**	**7 227**	**- 1310**

Source: Natural Resources Canada

Table 10.5
Major Electric Utility Long-Term Debt and Sources of Financing, 1994

	Long-term Debt	Sources of Long-term Debt Financing	
	($ millions)	Domestic (%)	Foreign (%)
Newfoundland and Labrador Hydro	1 306	66	34
Newfoundland Light & Power	208	100	0
Maritime Electric Co. Ltd.	52	100	0
Nova Scotia Power	1 100	87	13
NB Power	3 059	65	35
Hydro-Québec	36 047	42	58
Ontario Hydro	30 202	84	16
Manitoba Hydro	4 412	39	61
Saskatchewan Power	1 832	66	34
Alberta Power	843	100	0
Edmonton Power	1 112	100	0
TransAlta Utilities	1 458	100	0
B.C. Hydro	7 680	74	26
Yukon Development Corporation	68	100	0
Northwest Territories Power Corp.	90	100	0
Canada	**89 469**	**63**	**37**

Source: Natural Resources Canada

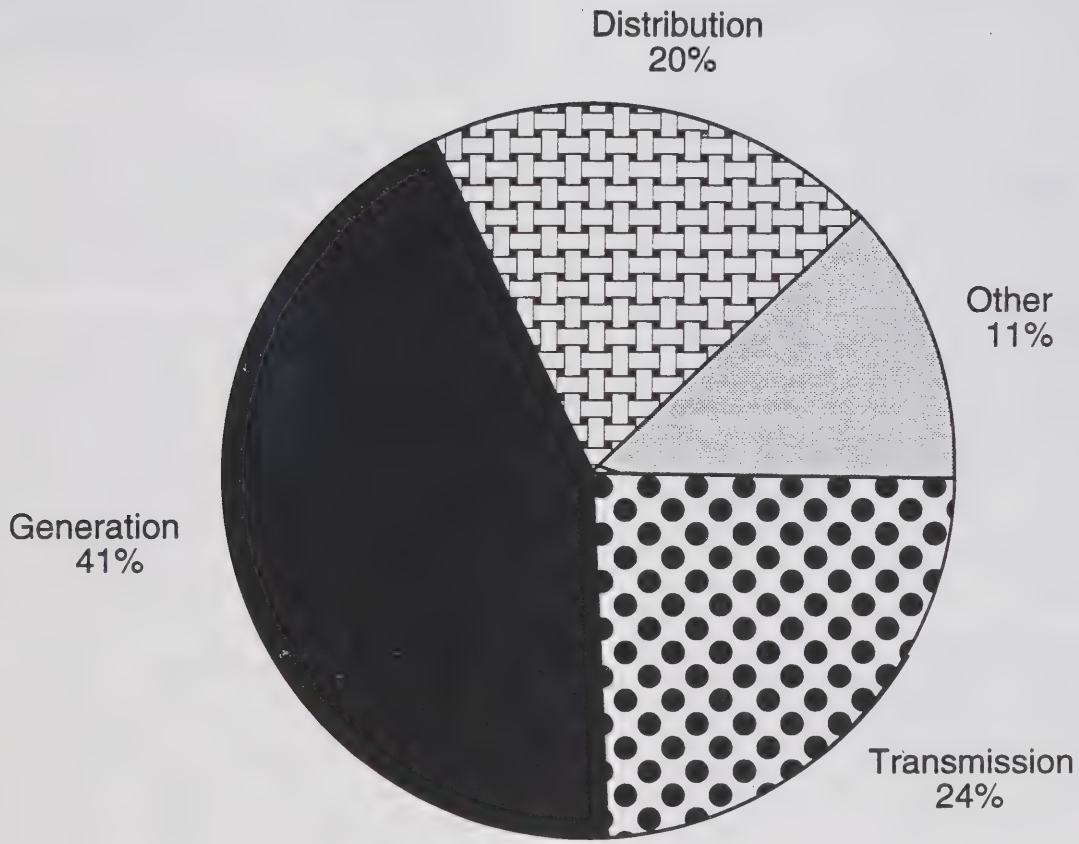
Table 10.6
Comparison of Canadian and U.S. Electric Utility Debt Ratios, 1988-1993

	1988	1989	1990	1991	1992	1993
			(per cent)			
CANADA						
Publicly Owned Utilities						
Newfoundland and Labrador Hydro	83	82	84	74	83	82
NB Power	83	82	83	82	87	89
Hydro-Québec	74	74	75	76	76	76
Ontario Hydro	83	83	83	84	84	92
Manitoba Hydro	95	95	94	94	95	93
Winnipeg Hydro	75	69	68	64	68	73
Saskatchewan Power	81	74	69	67	68	68
Edmonton Power	75	76	73	73	74	73
B.C. Hydro	81	80	79	75	75	78
Investor-Owned Utilities						
Newfoundland Light & Power	44	48	43	41	46	49
Maritime Electric Co. Ltd.	47	47	39	44	43	44
Nova Scotia Power*	99	97	96	95	68	61
TransAlta Utilities Corporation	39	41	45	40	40	38
Alberta Power	38	41	46	42	46	44
UNITED STATES						
Publicly Owned Utilities						
Tennessee Valley Authority	83	81	84	84	88	88
Bonneville Power Administration	100	100	100	100	100	100
Power Authority of the State of New York	69	68	70	75	74	74
Investor-Owned Utilities						
Boston Edison Company	50	52	55	54	51	54
Northeast Utilities	54	52	51	52	60	59
Consolidated Edison Company of New York	37	38	39	39	39	39
Niagara Mohawk Power Corporation	55	57	57	56	56	53
American Electric Power Company	52	47	50	50	51	50
Northern States Power Company	42	41	41	40	41	38
Washington Water Power Company	51	49	47	49	45	46
Pacific Gas and Electric Company	49	48	48	49	48	50

*Privatized in 1992.

Source: Natural Resources Canada

Figure 10.1 Capital Investment by Function, 1994



Total Investment: $7.2 billion

Costing and Pricing

Electricity Supply Costs

During the period 1962-1994, increases in the cost of building electric power stations, transmission lines, and distribution systems were relatively small, with the exception of oil crisis period.

The unit cost of supplying additional electricity increased rapidly during the period 1973-81 [which coincided with the first (1973) and second (1979) oil crises (see Table 11.1)]. There were two key reasons for the rapid increases in the cost of electricity: the high rate of inflation (as measured by the Consumer Price Index (CPI) or the Gross Domestic Product (GDP) deflator), with an average annual increase of 9.5 per cent; and the increased cost of fossil fuels, with an average annual increase of 15 per cent. In general, high levels of inflation affect the electric utility industry by increasing the cost of facility constructing and by increasing the cost of the funds required to finance the construction.

The average interest rate on long-term utility debt for the period 1962-94 is also shown in Table 11.1. Interest rates started to rise after the first oil crisis and reached a peak of 16.3 per cent in 1981. After this, they dropped steadily to about 10.8 per cent by 1991, 9.9 per cent by 1992, and 9.5 per cent by 1994.

Since 1982, construction cost increases have moderated significantly. Adjusted for inflation, recent increases in the supply cost of electricity have been very small or negative.

In 1991, the federal sales tax was removed from items where it had previously been deemed applicable. The Goods and Services Tax (GST) is not applied to any item within electric utilities construction costs; if utilities pay GST on their construction inputs, they are later reimbursed.

Table 11.2 summarizes the unit costs of the various fossil-fuels used for electricity generation. Like construction costs, unit fuel costs increased substantially during the period 1973-81. It is estimated that the cost of natural gas increased annually by an average of 30 per cent, petroleum by 23 per cent, eastern coal by 19 per cent, and western coal by 15 per cent.

Unit fossil-fuel costs reached a peak in 1985 but began to decline in 1986 with the collapse of world oil prices. In 1993, unit costs of electricity generation from petroleum and natural gas increased by about 9 and 6 per cent , respectively.

The unit cost of using coal for electricity generation for the western provinces also increased by 13 per cent, which was mainly attributed to coal price increases in Alberta and Saskatchewan. However, the unit cost from coal-fired generation in the eastern provinces increased by only 4 per cent resulting from an increase of imported coal prices.

The unit cost of electricity generated from coal varies between regions of the country depending upon the type of coal used, its source and the quantity required. The unit fuel cost of electricity generated from western Canadian coal increased from 1.11 mills per kWh in 1969 to 6.64 mills per kWh in 1993. In the same period, the cost of coal-fired generation in eastern Canada increased from 3.46 mills per kWh to 24.00 mills per kWh. This large cost-difference between the two regions is mainly due to the fact that coal used for electricity generation in western Canada is produced domestically, while a large proportion of the coal used in eastern Canada is imported.

Over the last 18 years, nuclear-generated electricity has had competitive unit fuel costs in Canada. In 1993, it cost 4.50 mills per kWh, compared with an average of 29.31 mills for petroleum, 19.88 mills for natural gas,

24.00 mills for eastern coal and 6.64 mills for western coal. However, in terms of percentage increases, the unit fuel cost of using uranium for electricity generation increased at an average annual rate of 8.4 per cent during the period 1976-93, compared with 4.5 per cent for eastern coal, 4.8 per cent for western coal, 3.9 per cent for petroleum and 3.1 per cent for natural gas.

Electricity Pricing

In Canada, electric utilities price electricity at the average cost of production, which is generally lower than the marginal cost of production. Although marginal-cost pricing of electricity has the advantage of achieving economic efficiency (i.e. closing the cost-price gap), this pricing method has not been adopted by the provinces and electric utilities because of the complexities of marginal costing and because average costing has provided low-cost electricity and enhanced opportunities for regional economic development.

Rate design has evolved since the first oil crisis of 1973, and several alternatives to marginal-cost pricing have been implemented. For example, declining block rates for residential users (i.e. the more you use the less you pay) have been replaced by a uniform rate in Newfoundland, Prince Edward Island, Saskatchewan, Alberta and the Yukon; seasonal time-of-use rates were introduced in Ontario in January 1989; and automatic adjustment clauses for the escalation of fuel costs have been built into the rate design of those utilities that operate baseload oil-fired stations. The objective of all of these rate design efforts is to close the cost-price gap. Rate methodologies will continue to evolve to meet the changing needs of customers.

Table 11.3 presents annual electricity rate increases for major electric utilities across Canada over the past 10 years. In 1994, Alberta Power had the highest rate increase with 5.0 per cent, followed by the Yukon Energy Corporation, 4.0 per cent. A weighted average for Canada was about 0.8 per cent, compared with 3.7 per cent in 1993. Increases were higher than the CPI, which registered increases of 1.8 per cent in 1993 and 0.2 per cent in 1994.

The average revenue from electricity sales for each province is provided in Table 11.4. Because electricity rates are regulated by provincial governments and are intended to cover a utility's costs, rate increases tend to parallel the rate of inflation. The average annual growth in unit revenue for Canada as a whole was 4.3 per cent during the period 1984-93. The national inflation rate, as measured by the CPI, was 3.9 per cent over the same period.

Figure 11.1 illustrates the movement of the electricity, oil and natural gas components of the CPI, as well as the CPI itself. It indicates that since the collapse of world oil prices in 1986, the electricity price component has increased in line with the CPI, while natural gas price indices have declined despite rising inflation. The oil price indices have also decreased since 1986, but have started to rise since 1990.

Income statements for the major electric utilities are summarized in Table 11.5. In 1994, 16 major electric utilities in Canada had total operating revenues of $25.2 billion and a net income of $2.1 billion, compared with a net loss of $1.9 billion in 1993. The net loss in 1993 was mainly due to Ontario Hydro's net loss of $3.6 billion, resulting from corporate restructuring in that year. Hydro-Québec had the largest net income of $667 million, followed by Ontario Hydro with $587 million, and B.C. Hydro with $190 million. Hydro-Québec's net income for 1993 was $761 million.

Electricity costs differ across the country primarily because of differences in generation mix, the size and location of the utility and its market, indigenous resources and geography. Table 11.6 gives typical monthly electricity bills for selected Canadian cities as of January 1995. Winnipeg had the lowest electricity costs in the residential and industrial sectors, and Vancouver in the commercial sector.

Tables and figures referred to in this chapter are on the following pages.

Tables & Figures

Table 11.1
Inflation, Interest Rates and Construction Costs, 1962-1994

	Average Interest Rate	Increase in Construction Costs					
		Hydro	Steam	Nuclear	Transmission	Distribution	CPI
				(per cent)			
1962	5.4	2.8	-	-	1.0	1.8	1.2
1963	5.5	3.3	-	-	1.5	0.4	1.7
1964	5.5	3.2	-	-	0.0	2.2	1.8
1965	5.7	5.0	-	-	5.7	2.2	2.5
1966	6.4	6.2	-	-	4.1	5.1	3.7
1967	6.7	3.6	1.1	-	5.2	1.6	3.5
1968	7.8	4.2	2.8	-	2.9	1.2	4.7
1969	8.6	5.7	6.8	-	4.4	4.3	4.5
1970	9.3	6.6	7.4	-	5.0	7.5	3.3
1971	8.5	4.6	6.0	-	5.5	3.5	2.9
1972	8.4	6.3	6.1	6.9	6.3	4.4	4.8
1973	8.6	9.2	9.2	9.5	8.8	9.4	7.6
1974	10.2	18.8	20.5	19.2	19.2	20.4	10.9
1975	10.7	14.3	13.4	13.1	17.6	12.3	10.8
1976	10.4	8.9	10.0	9.7	7.3	5.7	7.5
1977	9.6	5.9	7.9	7.5	7.8	6.6	8.0
1978	10.1	7.7	8.7	8.0	8.0	7.4	9.0
1979	10.9	8.7	11.0	12.7	14.8	13.5	9.2
1980	13.3	10.0	11.6	22.0	13.6	14.0	10.2
1981	16.3	13.7	11.9	11.4	11.3	9.1	12.5
1982	15.9	7.2	6.8	5.3	4.8	9.3	10.8
1983	12.7	4.6	4.1	5.0	3.8	4.1	5.8
1984	13.5	3.2	2.8	0.1	5.3	4.4	4.4
1985	11.7	1.7	3.8	4.8	0.9	5.2	4.0
1986	10.4	4.1	3.5	3.5	2.1	2.4	4.1
1987	10.7	4.1	3.0	1.9	3.8	3.1	4.4
1988	10.9	4.0	5.7	2.8	9.2	6.1	4.1
1989	10.8	3.4	4.2	5.1	3.6	3.8	5.0
1990	11.9	4.5	3.6	3.3	2.6	3.2	4.8
1991	10.8	6.1	2.0	1.8	2.2	-0.8	5.6
1992	9.9	2.7	1.7	-	-1.2	2.3	1.5
1993	8.8	2.7	1.0	-	3.1	2.9	1.8
1994	9.5	3.4	3.5	-	5.6	3.4	0.2

Source: Interest Rates - McLeod Young Weir Limited's average long-term corporate bonds yield. Construction costs and CPI-Statistics Canada publications 62-007 and 62-001

Table 11.2
Cost of Fuel for Electricity Generation, 1969-1993

	Eastern Coal*	Western Coal**	Petroleum	Natural Gas	Uranium	Total Fuels
			(mills/kWh)			
1969	3.46	1.11	4.97	2.54	-	3.24
1970	3.60	1.38	5.68	2.47	-	3.25
1971	4.20	1.28	5.98	3.15	-	3.46
1972	4.32	1.34	6.41	3.93	-	3.42
1973	4.65	1.43	7.06	3.74	-	3.13
1974	5.38	1.54	11.36	5.18	-	4.10
1975	8.64	2.07	12.87	7.17	-	6.16
1976	11.43	2.97	15.38	11.74	1.14	8.11
1977	11.89	3.20	19.01	15.21	1.34	8.40
1978	13.12	2.88	21.22	16.19	1.61	8.82
1979	16.50	3.11	23.93	15.22	1.65	9.62
1980	18.22	3.75	26.22	15.47	2.65	10.69
1981	20.48	4.83	40.77	23.22	2.68	12.22
1982	22.61	5.76	44.88	30.16	2.87	14.04
1983	23.71	5.96	57.27	31.17	3.25	13.20
1984	24.85	5.94	65.11	34.15	3.84	13.64
1985	26.07	6.59	68.02	31.81	4.74	13.54
1986	25.88	5.13	45.15	27.11	4.52	10.70
1987	25.07	5.84	37.22	22.20	4.77	11.63
1988	22.05	5.51	27.53	25.17	4.53	10.52
1989	20.96	5.63	29.08	18.78	4.62	11.16
1990	22.83	5.87	32.93	21.67	4.88	11.41
1991	22.32	6.60	31.24	22.20	5.01	10.90
1992	23.21	5.88	26.80	18.83	5.18	10.94
1993	24.00	6.64	29.31	19.88	4.50	9.96

* Nova Scotia, New Brunswick and Ontario.
** Alberta, Saskatchewan and Manitoba.

Source: Calculated from Electric Power Statistics, Statistics Canada, catalogue 57-202, various issues

Table 11.3
Average Annual Electricity Rate Increases, 1985-1994

	Rate Changes (%): Average of all Customer Classes									
	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
Nfld. & Labrador Hydro	-	-1.7	-	-	1.0	8.2	1.6	3.8	0.0	0.0
Nfld. Light & Power	-	8.7	3.0	-1.1	2.0	12.5	0.8	5.2	0.3	0.5
Maritime Electric Co.Ltd.	3.7	-3.8	-	-1.3	-	5.5	5.3	2.6	1.2	-7.0
Nova Scotia Power	-	-	-	-	6.3	2.5	5.0	2.1	1.8	0.0
NB Power	4.6	-	-	-	-	-	4.4	5.0	0.0	2.9
Hydro-Québec	4.0	5.4	4.9	3.9	4.7	7.4	7.0	3.5	1.5	1.0
Ontario Hydro	8.6	4.0	5.0	4.7	5.3	5.9	8.6	11.8	7.9	0.0
Manitoba Hydro	5.0	2.8	9.7	4.5	6.0	4.0	3.5	3.5	0.0	1.2
Saskatchewan Power	-	7.5	7.5	6.1	3.9	-1.9	-0.6	4.0	4.0	3.8
Edmonton Power	6.7	0	3.0	1.9	-	-	3.0	8.0	3.3	1.4
TransAlta Utilities	1.7	6.1	-1.8	-1.0	5.5	-1.1	12.0	3.0	2.0	1.4
Alberta Power	-4.3	-8.6	-5.0	14.5	2.6	3.7	17.0	7.0	5.1	5.0
B.C. Hydro	3.8	1.8	-	-	3.0	1.5	3.0	7.0	3.9	0.0
Yukon Energy	-	0.7	-	-	-	4.0	11.3	-2.3	6.8	4.0
NWT Electric	-	-	-	-	-	9.5	0	6.0	0.0	0.0
Weighted Canada	**6.2**	**4.1**	**4.2**	**3.5**	**4.3**	**4.9**	**6.8**	**7.2**	**3.7**	**0.8**

Source: Natural Resources Canada

Table 11.4
Average Revenue from Electricity Sales by Province, 1984-1993

	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
	(current cents/kWh)									
Newfoundland	3.9	4.7	3.9	4.0	4.0	4.1	4.4	4.9	4.7	4.9
P.E.I.	12.8	12.9	11.5	10.3	10.8	10.2	10.8	11.3	11.7	12.2
Nova Scotia	7.5	7.3	6.9	6.8	7.0	6.9	7.2	7.4	7.7	7.7
New Brunswick	5.5	5.8	5.5	5.5	5.3	5.5	5.2	5.6	5.6	5.8
Quebec	3.4	3.5	3.4	3.4	3.6	3.9	4.3	4.6	4.8	4.7
Ontario	4.2	4.5	4.5	4.9	5.1	5.4	5.7	6.3	7.0	7.4
Manitoba	3.4	3.6	3.6	3.9	4.0	4.1	4.3	4.5	4.7	4.6
Saskatchewan	4.5	4.8	5.0	5.5	5.8	6.1	6.0	5.9	5.9	6.1
Alberta	5.4	5.4	5.4	5.3	5.0	4.9	5.2	5.2	5.2	5.7
British Columbia	4.1	4.4	4.2	4.2	4.2	4.2	4.3	4.7	4.6	4.5
Yukon	8.6	9.0	7.8	7.4	7.7	7.1	7.3	7.9	8.0	10.9
N.W.T.	16.7	16.3	15.9	17.6	17.7	20.7	19.9	21.0	22.3	20.6
Canada	**3.9**	**4.1**	**4.3**	**4.2**	**4.5**	**4.8**	**5.0**	**5.3**	**5.6**	**5.7**

Source: Statistics Canada publication 57-202

Table 11.5
Major Electric Utilities' Statements of Income, 1994

	Total Revenue	O&M	Fuel Costs	Power Pur-chased	Depre-ciation	Taxes	Interest	Ex-change Losses	Other Costs	Net Income
	(millions of current dollars)									
Nfld. & Labrador Hydro	362	110	39	2	41	-	143	-	10	17
Nfld. Light & Power	334	51	-	188	28	20	23	-	(4)	28
Maritime Elec. Co. Ltd.	81	29	-	25	7	6	6	-	34	8
Nova Scotia Power	716	156	247	-	83	1	152	-	34	111
NB Power	942	271	151	86	160	-	333	-	(85)	26
Hydro-Québec	7 297	1 766	-	293	1 096	666	2 785	24	-	667
Ontario Hydro	8 732	1 705	577	316	1 593	284	3 402	-	268	587
Manitoba Hydro	944	234	-	10	156	63	425	-	-	56
Winnipeg Hydro	119	27	-	54	4	-	11	-	7	16
Saskatchewan Power	837	232	147	-	133	51	191	-	2	85
Alberta Power	595	136	79	-	87	105	86	-	26	76
Edmonton Power	670	84	-	135	48	38	136	-	154	75
TransAlta Utilities	1 261	268	104	-	225	302	159	-	16	187
B.C. Hydro	2 185	410	441	-	295	170	679	-	-	190
Yukon Dev. Corp.	17	8	-	-	4	-	-	-	-	5
N.W.T. Power Corp.	103	37	37	-	9	-	11	-	(2)	11
Canada	**25 196**	**5 524**	**1 822**	**1 109**	**3 969**	**1 706**	**8 542**	**24**	**354**	**2 145**

Source: Obtained from electric utilities' annual reports, 1993

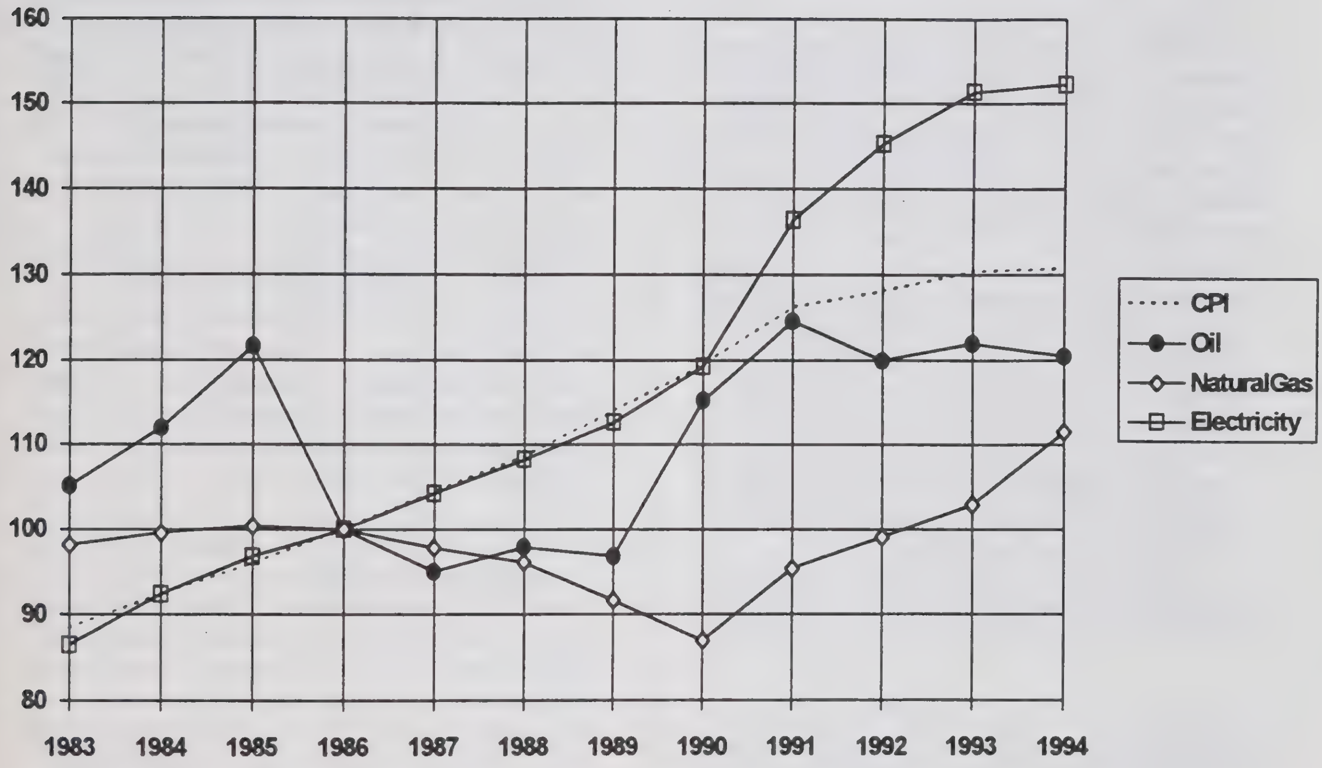
Table 11.6
Monthly Electricity Costs, January 1995 (Dollars)*

Sector:	**Residential**	**Commercial**	**Industrial**
Billing Demand (kW):	**-**	**100**	**1000**
Consumption (kWh):	**1000**	**25 000**	**400 000**
St. John's	86	2 594	24 477
Charlottetown	114	2 997	33 222
Halifax	97	2 742	26 982
Fredericton	83	2 356	23 231
Montreal	67	2 351	21 932
Ottawa	79	2 051	29 465
Toronto	101	2 826	34 500
Winnipeg	64	1 820	19 111
Regina	87	2 877	34 483
Calgary	70	2 144	22 859
Vancouver	67	1 683	19 976
Whitehorse	89	2 767	-
Yellowknife	141	3 546	-

* Bills computed include sales tax, discounts and subsidies.

Source: Natural Resources Canada

Figure 11.1 Price Indices, 1983 - 1994 (1986 = 100)



Electricity Outlook

Forecasts of electrical energy demand (kilowatt-hours) and peak load (kilowatts) are the starting points in the electric utility planning cycle. Forecasts of peak and energy demands are essential to ensure that sufficient generating capacity is available when it is needed. As the lead times required to add new generating capacity have lengthened, and the costs of new capacity have risen, the importance of forecasting has increased substantially.

The demand for electricity (both peak and energy) is affected by many variables. Some of them are easily identified while others are not; some can be measured, others cannot; in some cases their influence on the electricity load is rather straightforward, but in most cases the relationship is more subtle.

At the same time, forecasting electricity demand has become more difficult because of greater uncertainties about future input variables. Uncertainties associated with input variables, such as future electricity prices, fuel prices, economic growth, population, weather, efficiency standards, regulatory changes and other policy changes, create uncertainties in the forecasts of electricity demand. These uncertainties are in addition to the uncertainties inherent in the methodologies themselves used by electric utilities.

Forecasts of Electrical Energy Demand

As mentioned earlier, there are many factors affecting electrical energy demand. However, in the long-run, electricity demand will be mainly determined by economic and demographic activities. The economic activity is generally recognized as the most appropriate variable for explaining electricity demand. Slowdown or expansion of the economy plays a key role in determining electricity use. An increase or decrease of population will affect the formulation of households which, in turn, will also influence electricity use.

Economic and population growth in Canada over the next 16 years are expected to be significantly lower than the previous 34 years. It is estimated that the real Gross Domestic Product will grow at an average of only 2.5 per cent for the period 1994-2010, much less than the historical average of 3.9 per cent achieved during the period 1960-1994. Population is expected to grow at an average of 1.1 per cent for the period 1994-2010, less than the 1.5 per cent registered during the same period 1960-1994. In addition, it is expected that the country's economic structure will not shift greatly over the same period from predominantly service-producing industries to goods-producing industries. In general, goods-producing industries consume more electricity than those producing services. Demand-side management is expected to have greater emphasis in future electrical planning. Because of these expectations, electricity demand is projected to grow at a slower rate.

Table 12.1 summarizes electricity demand forecasts for the ten provinces and two territories. The projections of electrical energy demand within the service areas of the major electric utilities were prepared by the major utilities and provided to Natural Resources Canada in March 1995. Electricity demand for smaller utilities and industrial establishments was projected by the National Energy Board (NEB). The Energy Resources Branch of Natural Resources Canada (NRCan) combined these two sources of forecasts and produced a total electricity demand forecast for the provinces and territories. As Table 12.1 indicates, electricity demand for Canada as a whole is expected to grow at an average of 1.9 per cent during the period 1994-2010. This projected growth rate was slightly greater than last year's forecast of 1.7 per cent for the same period.

Figure 12.1 compares various forecasts for total electricity demand in Canada. Included for comparison, are the latest forecasts derived from NRCan's Interfuel Substitution Demand Model, the NEB's Supply and Demand Model, and forecasts provided by the major electric utilities. On the basis of the control case, the NEB's projection of electricity demand for the next 16 years is 2.0 per cent annually, compared with the utilities' 1.9 per cent, and NRCan's 1.5 per cent. The difference among these three forecasts is mainly due to different underlying economic assumptions. All of these forecasts, however, are significantly lower than the average annual growth rate of 4.5 per cent achieved during the period 1960-94.

Forecasts of Peak Demand

The operation of an electrical system must meet two basic requirements: to generate enough energy to meet energy demand, and to have enough capacity to satisfy peak demand. All major electric utilities in the ten provinces and two territories have their peak loads in winter. Table 12.2 reports winter peaks projected mainly by the major electric utilities for the period 1994-2010. For Canada as a whole, peak demand is expected to grow at an average annual rate of 1.3 per cent, which is slightly less than the 1.9 per cent projected for electrical energy demand. This suggests that the load factor for Canada's electrical system will improve slightly from 62.1 to 63.3 per cent during the period 1994-2010.

Forecasts of Generating Capacity

To meet the forecast growth in electricity demand shown in Tables 12.1 and 12.2, total installed generating capacity in Canada is expected to have a net addition of 13 787 MW during the period 1994-2010, with an average annual growth rate of 0.7 per cent (Table 12.3). This level of growth is slightly lower than those levels projected for energy and peak demand growth, reflecting the current surplus capacity situation in most of the provinces.

Table 12.4 presents installed generating capacity by fuel type for the period 1994-2010. Because of public concern about the environment, the capacity share of coal-fired generation is expected to decline significantly from about 18 per cent of the total capacity in 1994 to 16 per cent by the year 2010. On the contrary, the capacity share of hydro is expected to increase significantly at 56 per cent in 1994 to 58 per cent by 2010. Oil-fired generation is mainly reserved for peaking purposes and its capacity share is expected to stabilize at 7 per cent during the period 1994-2010. However, natural gas-fired generation will be used for both peaking and baseload requirements and its capacity share is estimated to increase from 4 per cent to 6 per cent of the total over the same forecast period. The nuclear share is projected to decrease slightly from 14 per cent of the total in 1994 to 12 per cent by 2010 due to the moratorium of the nuclear program in Ontario. Other installed capacity is expected to stabilize at 1 per cent in the forecast period 1994-2010.

Figure 12.2 compares various forecasts of total generating capacity in Canada. Between 1994 and 2010, the electric utilities projected new capacity additions of only 14 GW, or about 875 MW per year. Natural Resources Canada projects capacity additions of 12 GW, or 750 MW per year, and the National Energy Board projects new additions of 20 GW, or 1250 MW per year.

Forecasts of Electricity Generation

To meet both domestic electricity demand (Table 12.1) and export requirements (Table 12.7), the electric utilities have projected total electricity generation for the period 1994-2010 (Table 12.5). It is expected that hydro-based generation will continue to be the most important source of electric energy in Canada, with its share of total electricity production declining by 5 per cent, from 61 per cent in 1994 to 56 per cent in 2010. However, coal-fired production is expected to increase its market share by 2 per cent, from 15 per cent in 1994 to 17 per cent by 2010, largely because of using clean coal technologies.

Even though falling world oil prices in recent years have provided electric utilities with an economic incentive to utilize their existing oil-fired stations in the short term, oil prices are not expected to remain low for long. In the long term, oil-fired stations will continue to be used mainly for peaking capacity and to meet energy demand in remote locations. By the year 2010, the share of electricity generated from oil is expected to be stabilized at 2.0 per cent of total electricity generation.

In the long term, the use of natural gas for electricity generation is expected to increase to around 8 per cent of the total generation. This is because a great majority of independent power production, such as co-generation, is expected to use natural gas as the input fuel.

The nuclear share of electricity generation is expected to decline from 19 to 14 per cent during the period 1994-2010. The most recent new nuclear capacity comes from the Darlington station in Ontario, which was completed in 1993. With no other nuclear stations under construction, it is anticipated that the nuclear share of electricity generation will decline by the year 2010.

It is worth noting that electric utilities, particularly Ontario Hydro, B.C. Hydro and Hydro-Québec, have projected a considerable amount of electricity to be derived from independent power production. Table 12.6 indicates that electricity generation from other sources, including independent power production, is expected to increase substantially starting in 1995. By the end of 2010, independent power production is expected to account for about 7.6 per cent of total electricity generation, compared with only 0.8 per cent in 1994. It is estimated that about 64 per cent of the independent power production share will use natural gas.

A comparison of various forecasts of electricity generation for the period 1994-2010 is presented in Figure 12.3.

Forecasts of Electricity Exports to the United States

Canada and the United States enjoy essentially free trade in electricity: there is little direct government involvement in the contracting process, there are no tariffs, and there is no regulation over imports of electricity. With the North American Free Trade Agreement now in place, other non-trade barriers will be eliminated, gradually permitting an increase of electricity trade between the two countries. Table 12.7 reports electric utilities' projected electricity exports to the United States for the period 1994-2010. B.C. Hydro's projections of electricity exports to the United States are always on the low side because interruptible sales are not incorporated into this forecast.

Forecasts of Fuel Requirements

Forecasts of fuel requirements for the period 1994-2010 are based on the forecasts of energy generation given in Table 12.6. Between 1994 and 2010, electricity generated from coal-fired stations is estimated to increase by 42 per cent, however, coal requirements are expected to increase by only 16 per cent. This is because an increase of coal-fired generation is forecasted to take place particularly in New Brunswick, Nova Scotia, and Saskatchewan, where more efficient coal-fired plants are under construction or will be built. Alberta, which is traditionally a coal user province, is expected to reduce its coal-fired generation between 1994 and 2010, while Ontario will be increasing its coal-fired generation significantly during the same period.

The use of oil for electricity generation is restricted to meeting peak demand and providing electricity to remote communities.

However, the use of natural gas for electricity generation is projected to increase substantially between 1994 and 2010. Major industrial establishments, mainly in Alberta and Ontario, are the largest users. Electric utilities in Alberta and British Columbia also use a substantial amount of natural gas for electricity generation. Independent power producers, such as co-generators, are expected to use natural gas as input fuel in the provinces of Ontario and Quebec.

Nuclear energy is an important component of Canada's electricity supply. However, the use of uranium for electricity generation is expected to decrease during the period 1994-2010, due to the fact that no new nuclear stations are under construction and some existing stations are expected to retire.

Forecasts of Capital Expenditures

Over the next ten years 1995-2004, major electric utilities in Canada are expected to invest about $61 billion in facilities, an average of $6 billion per year. Quebec will be the largest investor, with $34 billion, accounting for 56 per cent of the total. A large share of this capital investment is expected to be spent on the James Bay Phase II and Grande Baleine hydro projects. Ontario is expected to invest only $11 billion in electrical energy, or about 18 per cent of Canada's total. Most of this expenditure will be used for hydro projects due to the completion of the Darlington Nuclear Station in 1993 (Table 12.9).

The electric utilities' capital investments by function are given in Tables 12.10 - 12.13. It is expected that generating facilities will account for 42 per cent of the total for the period 1995-2004, distribution 22 per cent, transmission 20 per cent, and other facilities 16 per cent.

Forecasts of Emissions from Electricity Generation

Electric utilities project that carbon dioxide emissions will continue to decrease until 1995, from 95 million tonnes in 1994 to 93 million tonnes in 1995, due to the reduction of coal use for power generation. It is then estimated to increase gradually to 139 million tonnes by the year 2010. (Figure 12.4). Coal-fired generation is expected to account for 86 per cent of the total, followed by 8 per cent for natural gas, and 6 per cent for oil.

Because of the application of new technologies to reduce emissions, electric utilities project that their sulphur dioxide emissions will be increased by only 18 per cent over the period 1994-2010, despite a 42 per cent increase in the electricity generation from coal-fired stations during the

same forecast period. (Table 12.14). The projections of nitrous oxides emissions are shown in Table 12.15.

Tables and figures referred to in this chapter are on the following pages.

Tables & Figures

Table 12.1
Forecasts of Domestic Electrical Energy Demand (GWh)

	1994*	1995	1996	2000	2005	2010	Average Annual Growth Rate 1994-2010 (%)
Newfoundland	10 959	12 170	12 459	13 431	14 506	15 458	2.2
P.E.I.	816	835	868	969	1 097	1 242	2.7
Nova Scotia	9 974	10 189	10 613	11 217	12 425	13 827	2.1
Mew Brunswick	14 205	14 906	15 195	16 587	17 935	19 437	2.0
Quebec	172 172	175 325	178 924	193 329	205 345	215 136	1.4
Ontario	137 430	148 726	152 956	168 526	183 444	195 866	2.2
Manitoba	18 901	18 584	18 925	20 742	22 288	23 590	1.4
Saskatchewan	15 926	16 421	16 300	17 273	17 948	18 972	1.1
Alberta	50 195	51 201	51 752	56 889	61 947	66 274	1.8
British Columbia	59 310	65 172	66 372	74 742	81 442	87 442	2.5
Yukon	297	375	513	503	540	545	3.9
N.W.T.	591	623	629	619	619	619	0.3
Canada	**490 776**	**514 527**	**525 506**	**574 827**	**619 536**	**658 408**	**1.9**

Table 12.2
Forecasts of Domestic Peak Demand (MW)

	1994*	1995	1996	2000	2005	2010	Average Annual Growth Rate 1994-2010 (%)
Newfoundland	1 820	1 920	1 938	2 014	2 154	2 266	0.7
P.E.I.	148	152	155	171	191	213	2.3
Nova Scotia	1 731	1 970	1 983	2 080	2 298	2 549	2.3
New Brunswick	2 853	3 034	3 139	3 465	3 731	4 016	1.8
Quebec	33 755	35 627	36 534	39 879	42 579	44 879	1.3
Ontario	26 718	25 029	25 512	27 909	30 205	32 152	1.0
Manitoba	3 268	3 597	3 689	3 970	4 310	4 645	2.2
Saskatchewan	2 525	2 649	2 549	2 700	2 783	2 928	0.7
Alberta	6 965	7 479	7 619	8 320	9 054	9 688	1.6
British Columbia	10 227	10 777	11 131	12 886	13 946	15 176	1.4
Yukon	62	85	85	86	87	88	2.2
N.W.T.	95	123	124	123	123	120	0.0
Canada	**90 167**	**92 442**	**94 458**	**103 603**	**111 461**	**118 720**	**1.3**

* Actual data

Source: Canadian Electric Utilities and the National Energy Board

Table 12.3
Forecasts of Installed Generating Capacity by Province (MW)

	1994*	1995	1996	2000	2005	2010	Average Annual Growth Rate 1994-2010 (%)
Newfoundland	7 453	7 460	7 461	7 587	7 685	7 835	0.3
P.E.I.	121	121	121	121	121	121	0.0
Nova Scotia	2 314	2 298	2 322	2 326	2 443	2 708	1.0
New Brunswick	4 378	4 119	4 102	4 225	4 435	4 738	0.5
Quebec	32 906	34 501	35 457	35 652	38 781	41 553	1.5
Ontario	36 573	34 577	34 800	35 301	35 838	35 838	0.1
Manitoba	4 911	4 897	4 765	4 765	4 633	4 528	0.5
Saskatchewan	3 079	3 121	3 121	3 181	3 191	3 291	0.4
Alberta	8 787	8 903	9 084	9 181	9 991	11 136	1.5
British Columbia	13 009	13 134	13 134	13 819	13 861	15 536	1.1
Yukon	134	136	136	136	137	138	0.2
N.W.T.	212	214	217	233	242	242	0.8
Canada	**113 877**	**113 481**	**114 720**	**116 527**	**121 358**	**127 664**	**0.7**

Table 12.4
Forecasts of Installed Generating Capacity by Fuel Type in Canada (MW)

	1994*	1995	1996	2000	2005	2010
Coal	20 900	19 661	19 529	19 473	19 853	20 188
Oil	8 119	7 253	7 616	7 684	8 011	8 265
Natural Gas	4 201	4 607	5 046	5 852	6 691	7 641
Nuclear	16 393	15 529	15 529	15 529	15 529	14 849
Hydro**	63 234	65 247	65 690	66 471	69 747	74 194
Other***	1 030	1 184	1 310	1 518	1 527	2 527
Total	**113 877**	**113 481**	**114 720**	**116 527**	**121 358**	**127 664**

* Actual data
** Includes 20 MW of tidal power
*** Generating capacity from woodchips and waste gases

Source: Canadian Electric Utilities and the National Energy Board

Table 12.5
Utility Forecasts of Electricity Generation by Province (GWh)

	1994*	1995	1996	2000	2005	2010	Average Annual Growth Rate 1994-2010 (%)
Newfoundland	38 405	38 230	40 611	42 349	42 778	43 182	0.7
P.E.I.	40	35	35	35	45	45	0.7
Nova Scotia	9 760	11 412	10 499	11 097	12 447	13 784	2.2
New Brunswick	15 867	15 610	17 435	19 067	20 455	21 531	1.9
Quebec	162 899	169 668	164 268	179 321	185 821	196 921	1.2
Ontario	148 433	147 626	153 707	165 019	177 057	189 033	1.5
Manitoba	28 435	29 475	29 857	28 767	28 182	28 909	0.1
Saskatchewan	15 471	15 889	16 110	16 890	17 364	18 146	1.0
Alberta	52 295	50 850	51 449	54 859	60 296	64 546	1.3
British Columbia	61 015	66 724	69 094	73 158	79 430	85 113	2.1
Yukon	297	375	513	535	540	545	3.9
N.W.T.	591	614	622	609	609	609	0.2
Canada	**533 508**	**546 508**	**554 200**	**591 706**	**625 024**	**662 364**	**1.4**

Table 12.6
Forecasts of Electricity Generation by Fuel Type in Canada (GWh)

	1994*	1995	1996	2000	2005	2010
Coal	81 204	81 176	80 790	90 915	102 224	115 566
Oil	6 105	9 426	9 073	11 290	14 117	14 391
Natural Gas	15 495	16 327	22 062	33 937	43 533	55 608
Nuclear	101 730	94 490	99 907	96 091	97 071	93 500
Hydro**	324 686	339 748	336 536	352 459	360 623	373 297
Other	4 288	5 341	5 832	7 014	7 456	14 002
Total	**533 508**	**546 508**	**554 200**	**591 706**	**625 024**	**662 364**

* Actual data

** Electrical generation from woodchips, waste gases, and non-utility generators.

Source: Canadian Electric Utilities and the National Energy Board.

Table 12.7
Electricity Exports to the United States (GWh)

	1994*	1995	1996	2000	2005	2010
New Brunswick	2 338	668	1 231	2 374	2 200	2 084
Quebec	16 835	19 400	9 100	9 500	2 400	2 400
Ontario	12 664	6 900	6 600	6 000	6 000	6 000
Manitoba	8 854	9 348	9 492	7 490	6 229	5 676
Saskatchewan	21	112	112	112	24	24
British Columbia	4 111	4 889	5 608	3 957	3 749	3 588
Canada	**44 823**	**41 317**	**32 143**	**29 433**	**20 602**	**19 772**

Table 12.8
Fuels Required for Electricity Generation in Canada

	Coal (10^3tonnes)	Oil (10^3m^3)	Natural Gas (10^6m^3)	Uranium (tonnes)
1994*	46 418	2 453	3 219	1 740
1995	45 442	2 971	4 097	1 542
1996	47 285	2 887	5 340	1 688
2000	51 421	3 490	7 792	1 610
2005	52 055	4 340	10 665	1 590
2010	53 596	4 371	12 605	1 512

* Actual data

Note: Average heat content for fuels used in electricity generation in Canada are as follows:

Coal (kj/kg): Bituminous = 29 579, Subbituminous = 18 373, Lignitie = 14 839, Total = 20 966.
Oil (kj/litre): Light = 38 403, Heating = 41 799, Diesel = 37 663, Total = 41 393.
Natural Gas (kj/m^3): 38 042
Uranium (kj/g): 690 687

Source: Canadian Electric Utilities and the National Energy Board

Table 12.9
Forecast of Capital Expenditures for Major Electric Utilities (Total)

	1994*	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
					(millions of current dollars)						
Nfld.	61	76	84	70	88	109	109	109	109	109	109
P.E.I.	14	11	11	9	10	28	13	13	13	13	13
N.S.	93	78	88	98	74	70	75	75	76	79	82
N.B.	148	152	111	104	87	92	92	92	92	92	92
Que.	3 298	2 985	2 800	2 800	2 651	2 767	2 964	4 062	4 168	4 530	4 632
Ont.	1 379	707	1 201	1 176	1 142	1 177	1 230	1 051	1 069	1 119	1 119
Man.	260	262	402	324	258	133	189	233	262	215	179
Sask.	201	243	299	245	231	209	169	152	163	153	153
Alta.	386	350	326	314	298	304	367	356	289	289	292
B.C.	415	442	497	498	608	605	536	429	385	357	494
Yukon	8	7	7	10	10	8	8	8	8	8	8
N.W.T.	17	22	18	16	12	12	12	12	12	12	12
Canada	**6 290**	**5 335**	**5 844**	**5 664**	**5 469**	**5 514**	**5 764**	**6 592**	**6 646**	**6 976**	**7 185**

Table 12.10
Forecast of Capital Expenditures for Major Electric Utilities (Generation)

	1994*	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
					(millions of current dollars)						
Nfld.	16	13	11	14	45	67	67	67	67	67	67
P.E.I.	5	3	2	1	1	21	5	5	5	5	5
N.S.	32	24	29	30	25	20	20	20	20	21	22
N.B.	75	59	8	8	5	16	16	16	16	16	16
Que.	1 328	1 168	1 024	1 104	1 101	1 200	1 400	1 985	2 063	2 406	2 513
Ont.	752	138	583	599	591	573	588	494	496	542	542
Man	74	101	159	88	39	54	46	45	51	43	44
Sask.	47	79	82	50	53	51	16	15	18	9	17
Alta.	171	133	116	105	92	102	150	155	90	90	90
B.C.	40	82	144	164	194	185	128	55	18	8	54
Yukon	3	2	2	3	3	2	2	2	2	2	2
N.W.T.	11	16	12	10	10	10	10	10	10	10	10
Canada	**2 554**	**1 818**	**2 172**	**2 176**	**2 159**	**2 301**	**2 448**	**2 869**	**2 856**	**3 219**	**3 382**

*Actual data

Source: Canadian Electric Utilities and Natural Resources Canada

Table 12.11
Forecast of Capital Expenditures for Major Electric Utilities (Transmission)

	1994*	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
	(millions of current dollars)										
Nfld.	8	18	28	6	2	2	2	2	2	2	2
P.E.I.	1	1	2	1	2	0	1	1	1	1	1
N.S.	5	8	13	21	3	3	8	8	8	9	9
N.B.	9	14	24	19	13	11	11	11	11	11	11
Que.	957	728	705	563	523	524	521	799	811	787	749
Ont.	214	210	265	271	224	263	288	194	196	242	242
Man.	103	55	122	104	99	-43	16	65	76	49	10
Sask.	15	29	48	41	21	15	10	4	4	4	3
Alta.	65	62	56	64	68	64	75	61	61	61	64
B.C.	120	95	110	90	93	98	108	105	108	105	182
Yukon	1	1	1	1	2	1	1	1	1	1	1
N.W.T.	1	1	1	1	1	1	1	1	1	1	1
Canada	**1 499**	**1 222**	**1 375**	**1 182**	**1 051**	**939**	**1 047**	**1 252**	**1 280**	**1 273**	**1 275**

Table 12.12
Forecast of Capital Expenditures for Major Electric Utilities (Distribution)

	1994*	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
	(millions of current dollars)										
Nfld.	28	32	30	32	32	32	32	32	32	32	32
P.E.I.	7	6	6	6	6	6	6	6	6	6	6
N.S.	38	33	36	38	38	39	39	39	40	41	42
N.B.	37	36	38	38	37	33	33	33	33	33	33
Que.	509	482	500	525	501	501	499	655	656	674	705
Ont.	160	145	165	165	156	156	170	179	169	197	197
Man.	43	74	82	89	78	75	77	80	77	77	80
Sask.	126	115	151	136	137	123	124	114	120	119	115
Alta.	117	111	104	99	99	98	102	100	98	98	98
B.C.	185	190	194	195	196	198	200	202	205	207	210
Yukon	3	3	3	5	4	4	4	4	4	4	4
N.W.T.	3	3	3	3	1	1	1	1	1	1	1
Canada	**1 256**	**1 230**	**1 312**	**1 331**	**1 285**	**1 266**	**1 287**	**1 445**	**1 441**	**1 489**	**1 523**

*Actual data

Source: Canadian Electric Utilities and Natural Resources Canada

Table 12.13
Forecast of Capital Expenditures for Major Electric Utilities (Other)

	1994*	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
	(millions of current dollars)										
Nfld.	9	13	15	18	9	8	8	8	8	8	8
P.E.I.	1	1	1	1	1	1	1	1	1	1	1
N.S.	18	13	10	9	8	8	8	8	8	8	9
N.B.	27	43	41	39	32	32	32	32	32	32	32
Que.	504	607	571	608	526	542	539	623	638	663	665
Ont.	253	214	188	141	171	185	184	184	208	138	138
Man.	40	32	39	43	42	47	50	43	58	46	45
Sask.	13	20	18	18	20	20	19	19	21	21	18
Alta.	43	44	50	46	39	40	40	40	40	40	40
B.C.	70	75	49	49	125	124	100	67	54	37	48
Yukon	1	1	1	1	1	1	1	1	1	1	1
N.W.T.	2	2	2	2	0	0	0	0	0	0	0
Canada	**981**	**1 065**	**985**	**975**	**974**	**1 008**	**982**	**1 026**	**1 069**	**995**	**1 005**

*Actual data

Source: Canadian Electric Utilities and Natural Resources Canada

Table 12.14
Forecasts of SO_2 Emissions by Fuel Type in Canada (1 000 tonnes)

Year	Coal	Oil
1994	466	76
1995	428	96
1996	452	90
2000	488	114
2005	497	138
2010	550	126

Source: Canadian Electric Utilities

Table 12.15
Forecasts of NO_x Emissions by Fuel Type in Canada (1 000 tonnes)

Year	Coal	Oil	Natural Gas
1994	147	13	8
1995	162	29	7
1996	171	22	8
2000	191	28	9
2005	199	39	22
2010	220	36	25

Source: Canadian Electric Utilities

Figure 12.1 Comparison of Electrical Energy Demand Forecasts in Canada

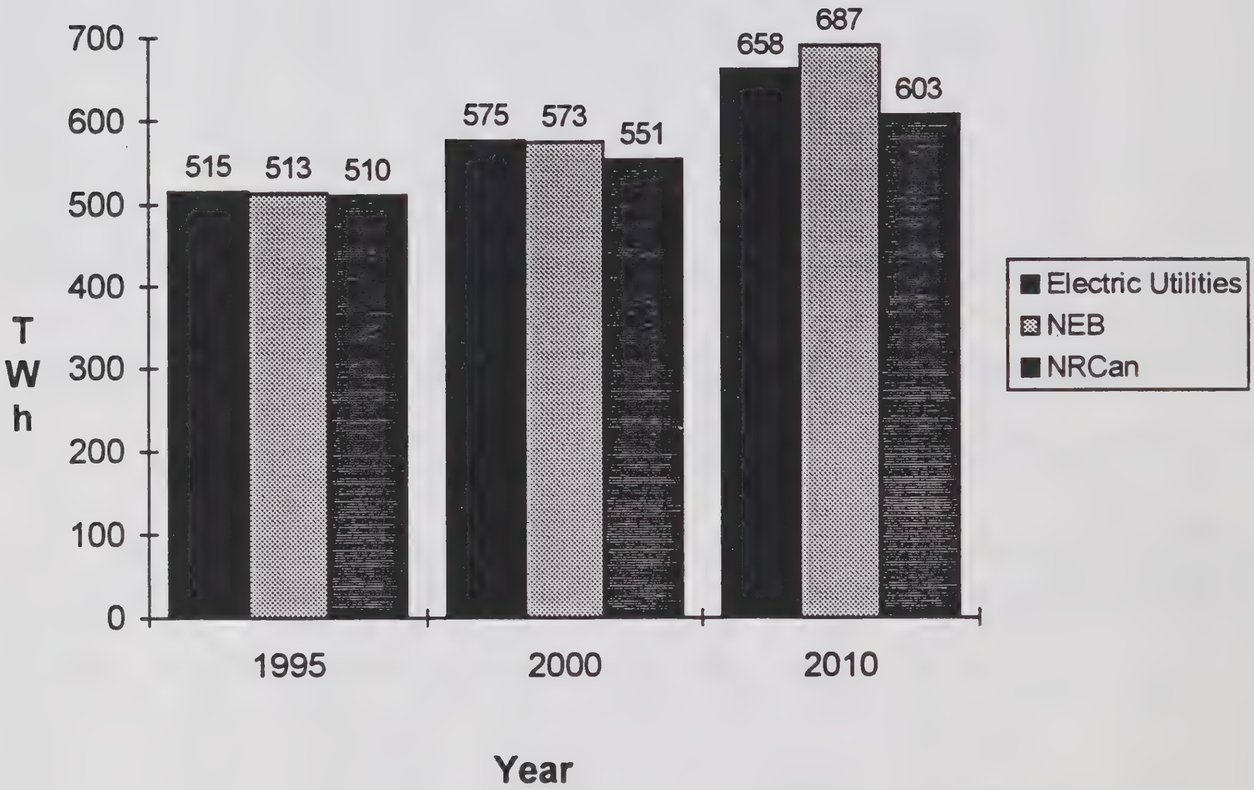


Figure 12.2 Comparison of Installed Generating Capacity Forecasts in Canada

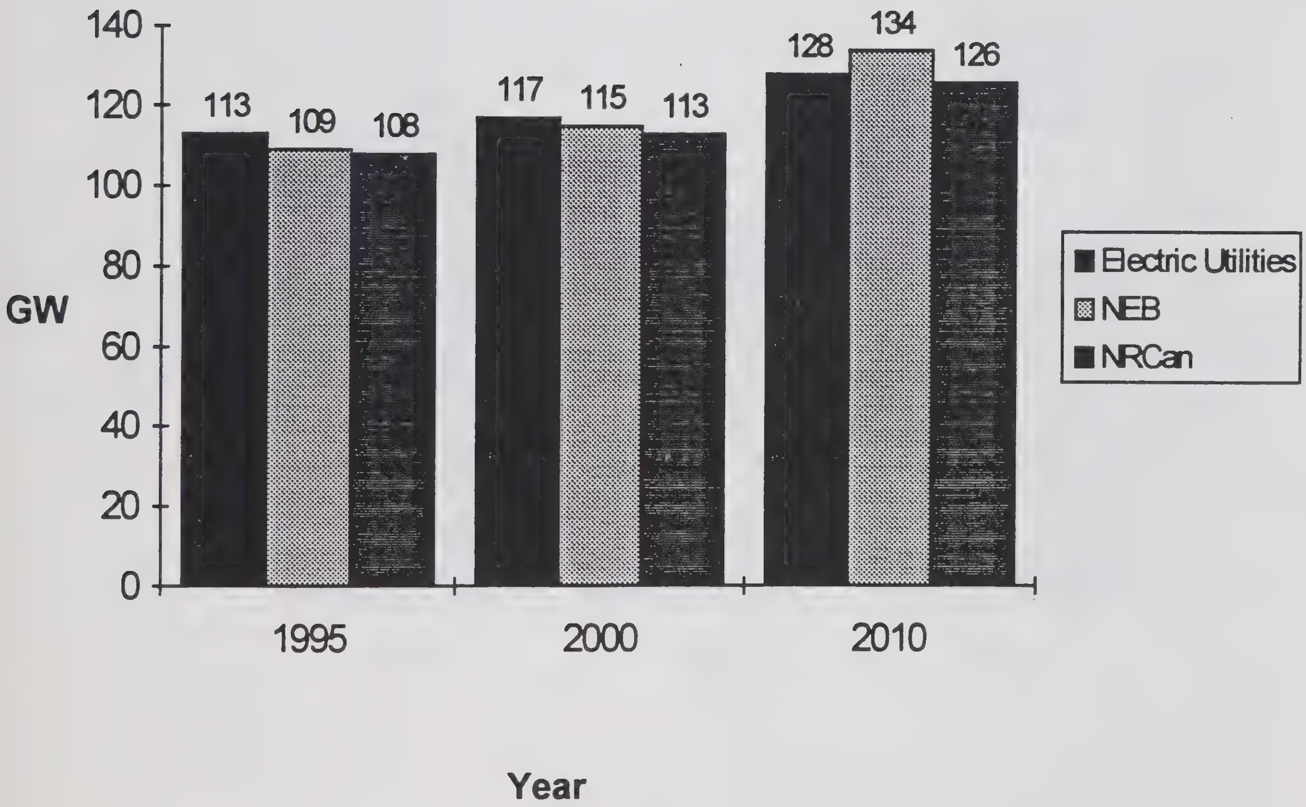


Figure 12.3 Comparison of Electricity Generation Forecasts in Canada

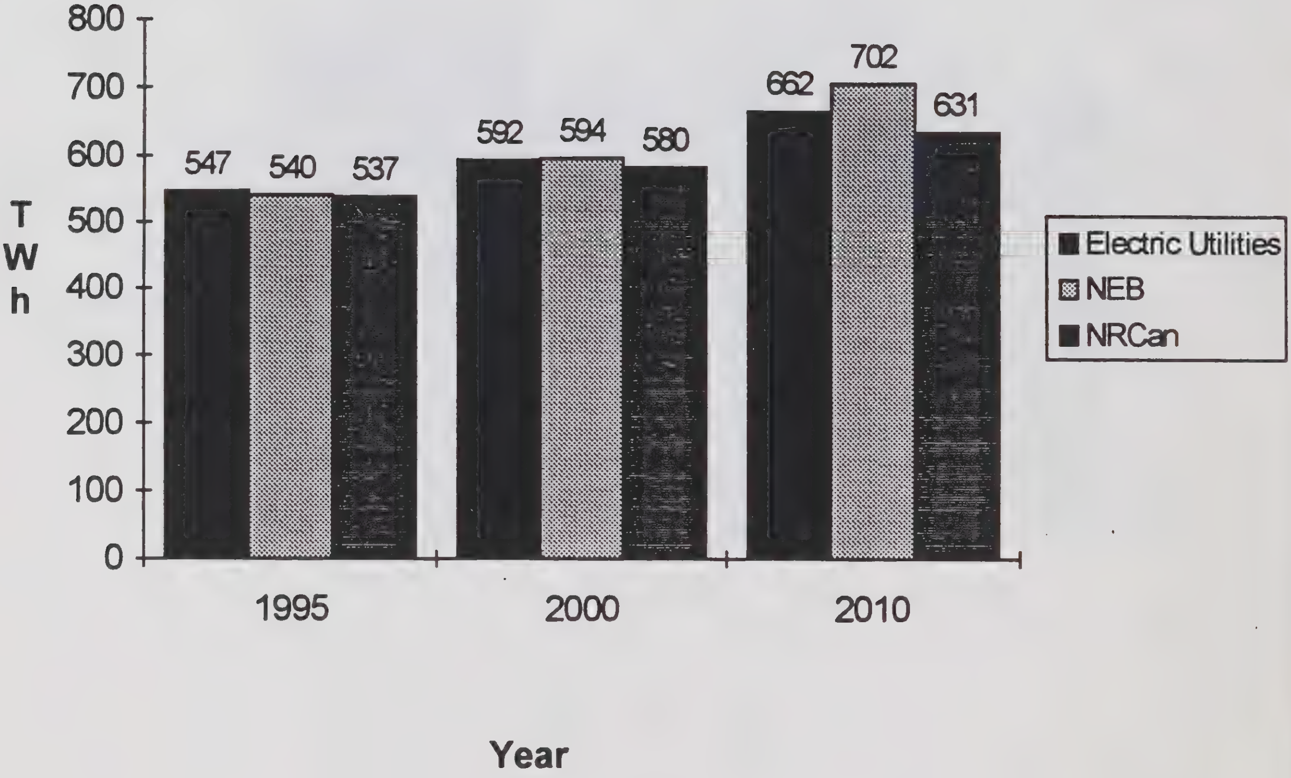
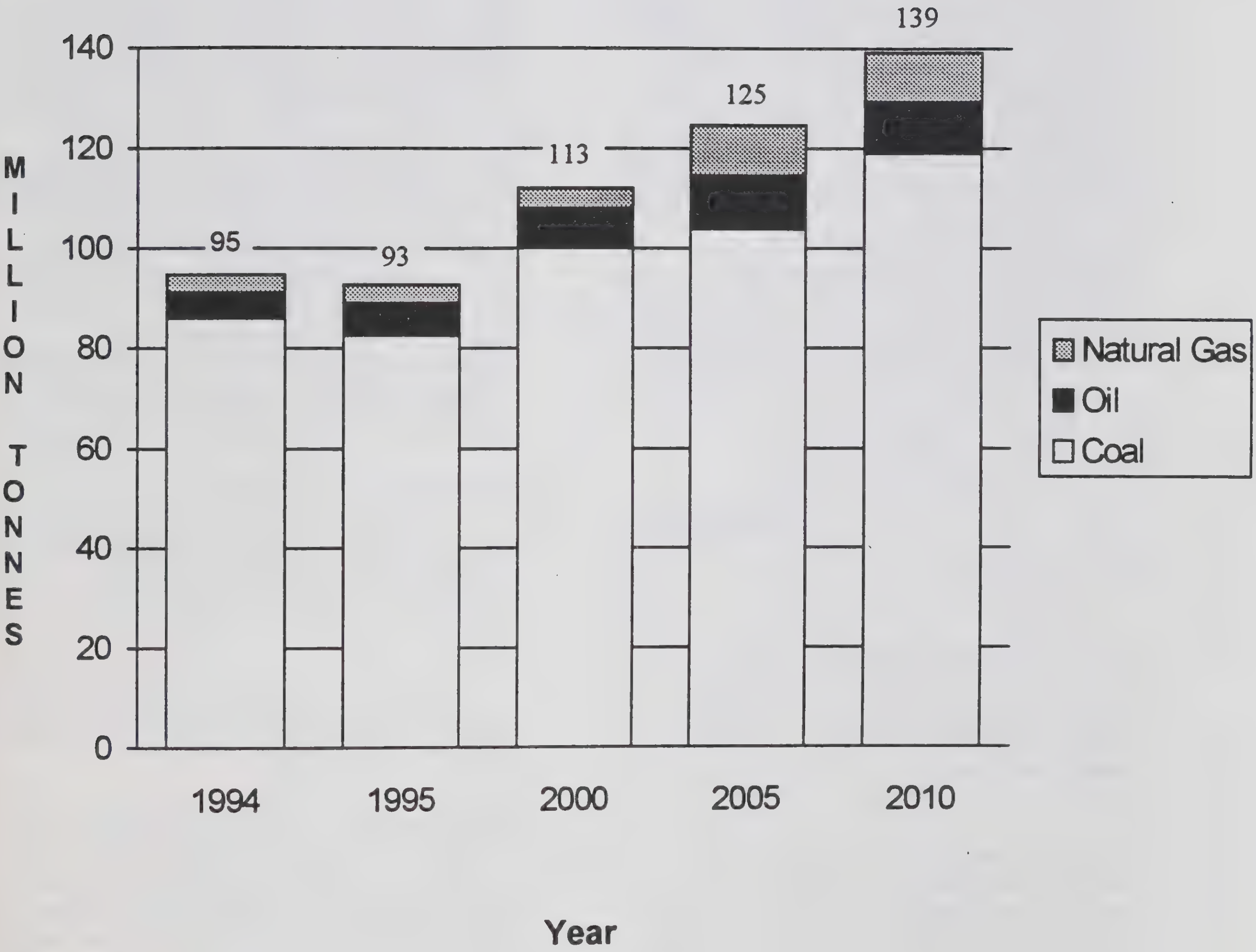


Figure 12.4 Forecasts of CO_2 Emissions by Fuel Type



Demand-Side Management

Importance of Demand-Side Management

Demand-Side Management (DSM) is defined as the planning and implementation of electric utility activities that influence customer use of electricity in ways that will promote desirable changes in the utility's load shape.

Managing electrical demand is not a new concept for Canadian electric utilities. Utilities have been offering lower rates for interruptible service for many decades, and utility research into improving the efficiency of lighting dates back to the beginning of the century. Since entering the 1990s, however, the utilities have been increasing their efforts in demand-side management, and in some provinces individual initiatives are being integrated into comprehensive demand-management programs. Some of the programs include, Hydro-Québec's Energy Efficiency Project; Ontario Hydro's fuel substitution and efficiency standards; TransAlta Utilities' demand-oriented rates; and B.C. Hydro and SaskPower's *Power Smart*, which is designed to create an awareness of energy conservation. Canadian utilities see these programs as a means of providing quality electrical service in a flexible, economic and environmentally sensitive manner.

The traditional role of the electric utility has been to respond to increases in the demand for electrical energy by building new generating capacity. This approach has led to surplus capacity and a waste of resources when the increased demand did not materialize.

Operations designed to meet rather than manage load have cost implications for the utility and eventually the utility's customers. Under traditional utility planning practices, an increase in load results in a need to bring additional generating resources on-line. Over time, utilities are forced to develop more expensive generating resources, e.g. isolated hydroelectric projects, new or different fuel sources, and imports. New developments become increasingly more expensive and in some cases, are also associated with large environmental costs.

To serve this load growth, utilities have had to adapt their operations to customer-use patterns. To do this while keeping generation costs low, utilities have had to optimize the use of their supply. Two considerations are important in this optimization: (i) the fixed and variable costs of various forms of production, and (ii) the costs of changing electrical output levels over a short period of time. As a result of these cost considerations, the most economic means of serving load, generally, has been for utilities to maximize the use of generation with (i) low variable cost sources (hydro and nuclear facilities) to serve baseload requirements and (ii) higher variable cost sources (coal, gas and pumped storage) to serve intermediate- and peak-load requirements. Figure 13.1 illustrates the resources that a typical utility might use to meet its annual load.

As Canadian utilities evaluate the means of providing electrical service to meet future demand, increasingly they are faced with a difficult choice between rising costs of generation and the cost of DSM options.

Objectives of DSM

Utilities generally pursue DSM in order to (i) maximize efficiency in their existing operations (i.e. reduce the use of costlier fuels and the period that generating plants sit idle); and (ii) minimize the requirement for new plants (i.e. reduce the need for peaking capacity, and delay the need for baseload capacity additions). The achievement of these goals brings a number of economic and environmental

benefits, particularly low electricity rates and reduced environmental impacts.

There are five key objectives of DSM. They are:

Load Reduction -- reducing the amount of electricity required by customers. This can be achieved by improving electrical end-use efficiency.

Load Shifting -- reducing peak electricity demand by moving it to periods of lighter demand. An example of this type of initiative is time-of-use rates that reflect the higher cost of providing electricity during periods of peak demand.

Peak Clipping -- reducing peak electricity demand without shifting it to another period. This can be achieved by offering preferential rates to consumers willing to have load interrupted during peak periods.

Valley Filling -- promoting electricity use during off-peak hours to increase baseload generation and the efficiencies related to it. This can be achieved through reduced rates.

Load Building -- promoting electricity consumption during both the peak and the off-peak periods. Load building can be done through incentives to attract large electricity consumers.

These classifications and examples of typical programs designed to achieve DSM objectives are illustrated in Figure 13.2.

A utility decides which aspects of DSM it will implement based on its balance of demand and supply. Utilities that find themselves with significant excess supply because of a major loss of load, a recent large capacity addition, or lower than anticipated load growth, will tend to emphasize load-building programs. Conversely, as utilities approach a load/resource balance, they will likely emphasize load reduction or shifting efforts.

During the early and mid-1980s, many Canadian utilities had surplus generating capacity resulting from lower than anticipated demand. At that time, some utilities introduced programs to build load. These initiatives included advertising campaigns to increase consumption, preferential rates designed to attract energy- intensive industries, programs to promote fuel switching to electricity, and increased electricity export marketing efforts.

Today, the focus has changed. As average Canadian net surplus capacity has declined from 14 per cent in 1980 to only 1 per cent in 1994 (see Table 7.7), utilities have cut programs to build load and begun to aggressively pursue load-reduction and load-shifting initiatives individually or in the context of a comprehensive DSM program. Generally these programs involve one or more alternative pricing policies, direct incentives, direct customer contact, and advertising.

DSM Initiatives

For ease of description, the types of initiatives utilities have embarked upon can be grouped into three classifications: energy efficiency improvements, load shifting, and interruptible load. Energy efficiency improvements are the main focus of electric utility DSM initiatives and programs.
Energy efficiency improvements include utility initiatives designed to increase the efficiency of electricity use among the utility's customers and thereby reduce load. These types of initiatives are generally intended to either improve the penetration of energy-efficient equipment in the marketplace or improve customers' operation of electrical equipment.

Load shifting refers to efforts by the utility to alter the timing of electrical demand among its customers. The goal of load shifting is to reduce peak demand that occurs in the daylight hours and, in Canada, during the winter. Demand is shifted to non-peak periods but total energy demand is not reduced.

Load shifting is more popular among utilities (i) where capacity is constrained, i.e., thermal as opposed to hydraulic systems, and (ii) where meeting the peak requires the operation of more expensive generating units or units with greater environmental impacts. Load shifting is generally done through rate design or direct control.

Interruptible load is the third type of DSM load reduction. It is also possibly the DSM initiative with which utilities have had the most experience. Interruptible load contracts are generally offered to large electricity consumers that have some form of back-up generation. Usually these are industrial or large institutional customers. In an interruptible load contract, the customer receives a preferential electricity rate in return for accepting the risk that electrical service will be curtailed intentionally by the utility in periods of high demand and tight supply.

Utility/Federal Cooperation

As outlined above, utilities implement a variety of programs in order to achieve their DSM objectives. Some of these programs are carried out in cooperation with Natural Resources Canada's (NRCan) Energy Efficiency Branch. NRCan's *Partners in Integrated Resources Planning (PIRP)* Initiative deals with electrical and natural gas DSM, non-utility generation, co-generation and district heating and cooling.

PIRP will bring together various stake-holders in order to increase the adoption of DSM, non-utility generation, and other energy management techniques within the energy sector. It will act to coordinate and catalyze integrated planning and program efforts. Joint activities will involve energy supply stakeholder and manufacturers and suppliers of energy efficient and energy management equipment.

Utilities in the Maritime provinces, for example, contribute to NRCan's *Federal Buildings Initiatives (FBI)*, which is aimed at introducing energy efficiency programs for federal facilities. Another example of utility partnership with NRCan is in Saskatchewan, where SaskPower and NRCan are investigating opportunities to implement energy efficiency at Regina Airport.

A number of utilities have also entered into agreements with NRCan to cooperate on ventures related to NRCan's *R-2000 Efficient Home Program, Energy Innovators,* and industrial energy programs.

DSM and Canadian Electric Utilities

Prior to 1994, Canadian electric utilities saved 5571 MW of generating capacity resulting from the implementation of DSM programs, which accounted for 5.0 per cent of the total installed generating capacity. Hydro-Québec had the highest savings of 3230 MW, followed by Ontario Hydro with 1113 MW and Alberta with 585 MW.

Table 13.1 summarizes Canadian utilities' forecasts of generating-capacity savings resulting from the implementation of DSM initiatives and programs for the years 1995, 2000 and 2010. The capacity savings are cumulative.

By the end of 1995, Canadian electrical utilities forecast DSM generating-capacity savings of about 5604 MW. The majority of the projected DSM savings will result from capacity interruptible load initiatives. This reflects mainly historic contracts with large consumers that are willing to accept occasional interruptions in service in exchange for reduced electrical rates. Most utilities offer such interruptible contracts. Hydro-Québec predicts 2410 MW of capacity interruptible load in 1995.

Load shifting will also contribute significantly to generating capacity savings, particularly as a result of Hydro-Québec's dual-energy program. Under this program, residential, commercial and industrial consumers use electricity for heating most of the time, but switch to another source of energy, such as heating oil, during peak heating periods (defined as when the temperature drops below a certain bench-mark). In exchange for switching off electricity during these peak periods, customers on this program receive a reduced rate for their off-peak consumption. Hydro-Québec projects a savings of 800 MW in load shifting in 1995.
Only 15 per cent of 1992 Canadian utility capacity savings from DSM came from energy-efficiency improvements. However, this percentage is expected to increase to 30 per cent in 1995, reflecting the time lag of program development, implementation and penetration.

By the year 2000, the total DSM savings are expected to climb to 9463 MW. At that time, about 49 per cent of the DSM savings will result from energy-efficiency improvements. These initiatives will be the basis of DSM programs for B.C. Hydro, Manitoba Hydro, Ontario Hydro, Hydro-Québec and New Brunswick Power. Utilities in Newfoundland, the Maritimes, Nova Scotia and Alberta will continue to rely on capacity interruptible load for the bulk of their DSM savings. Electrical efficiency improvements will continue to be the major source of generating capacity savings to the year 2010. By that time, total savings are expected to climb to 11 157 MW. Of this total, 6340 MW (or 57 per cent) is attributed to electrical efficiency improvements.

Figure 13.3 illustrates the sectors from which the forecast savings will come. The information shows that in 1995, 68 per cent of the savings will come from the industrial and residential sectors, reflecting the emphasis utilities have placed on energy efficiency improvements with these customers. By the year 2000, the distribution of savings will be more or less the same as in 1995. This reflects the anticipated success of energy-efficiency improvements in the industrial and residential sectors, particularly improvements in lighting efficiency.
Commercial savings are expected to account for 34 per cent of total peak-load savings by the year 2000.

Table 13.2 summarizes energy savings resulting from electrical efficiency improvements. It is estimated that about 8372 GWh of electricity will be saved in 1995, compared with 6110 GWh in 1993, and 7104 GWh in 1994. The real impact of initiatives in this area will be significant by the year 2000, approaching 22 283 GWh. The energy-savings are expected to increase to about 30 802 GWh by 2010.

Projected Capital Costs of DSM

Most utilities are unable to estimate the costs of the DSM programs and initiatives that they are planning to undertake. Part of the reason relates to difficulties in determining the penetration rate of such programs. Another reason is that load reduction programs account for much of the DSM effort, and establishing the costs of these programs is complex and in many instances dependent upon the frequency of unanticipated shortages. Some of the smaller utilities identified that their DSM planning is not as detailed nor as long-term as other resource planning.

In 1994, all electric utilities in Canada had invested a total of $344 million in DSM programs. Ontario Hydro was the largest spender with $163 million, followed by Hydro-Québec with $113 million and B.C. Hydro with $50 million. Only a few utilities have projected DSM expenditures to the year 2000: Hydro-Québec is intending to spend $236 million, followed by B.C. Hydro with $53 million and Manitoba Hydro with $36 million.

Tables and figures referred to in this chapter are on the following pages.

Chapter 13

Tables & Figures

Table 13.1
Generating Capacity Savings from Electric Utilities' DSM Cumulative Values

	1994	1995				2000				2010			
	Actual	EEI*	LS*	CIL*	Total	EEI	LS	CIL	Total	EEI	LS	CIL	Total
						(MW)							
Nfld.	0	0	1	46	47	0	1	46	47	0	1	46	47
P.E.I.	26	3	0	15	18	3	0	15	18	3	0	15	18
N.S.	166	12	0	170	182	68	0	187	255	239	0	236	475
N.B.	81	45	0	80	125	141	0	80	221	266	0	80	346
Que.	3 230	370	800	2 410	3 580	1 750	890	2 600	5 240	3 050	760	2 530	6 340
Ont.	1 113	1 011	260	0	1 271	1 638	422	0	2 060	1 638	422	0	2 060
Man.	66	29	0	50	79	122	0	81	203	266	0	88	354
Sask.	74	75	0	0	75	77	0	0	77	84	0	0	84
Alta.	585	31	12	507	550	178	20	507	705	178	20	507	705
B.C.	230	249	0	0	249	637	0	0	637	728	0	0	728
Yukon	0	0	0	0	0	0	0	0	0	0	0	0	0
N.W.T.	0	0	0	0	0	0	0	0	0	0	0	0	0
Canada	**9 074**	**1 825**	**1 073**	**3 278**	**6 176**	**4 614**	**1 333**	**3 516**	**9 463**	**6 452**	**1 203**	**3 502**	**11 157**

* Note: EEI - Electrical Efficiency Improvements
LS - Load Shifting
CIL - Capacity Interruptible Load

Source: Obtained from a survey undertaken by the Electricity Branch, Natural Resources Canada, January 1994

Table 13.2
Energy Savings from Electrical Utilities' Efficiency Improvement Programs

	1994 Actual	1995	2000	2010
		(GWh)		
Nfld.	0	0	0	0
P.E.I.	7	7	7	7
N.S.	0	40	246	815
N.B.	4	188	584	1 190
Quebec	1 140	1 770	8 000	14 000
Ontario	4 104	4 878	8 745	8 745
Manitoba	121	163	671	1 441
Sask.	185	182	170	191
Alberta	87	102	488	488
B.C.	1 456	1 042	3 372	3 925
Yukon	0	0	0	0
N.W.T.	0	0	0	0
Canada	**7 104**	**8 372**	**22 283**	**30 802**

Source: Obtained from a survey undertaken by the Electricity Branch, Natural Resources Canada, January 1994.

Figure 13.1 Typical Annual Load Duration Curve and Generation Cost Minimization for an Electric Utility

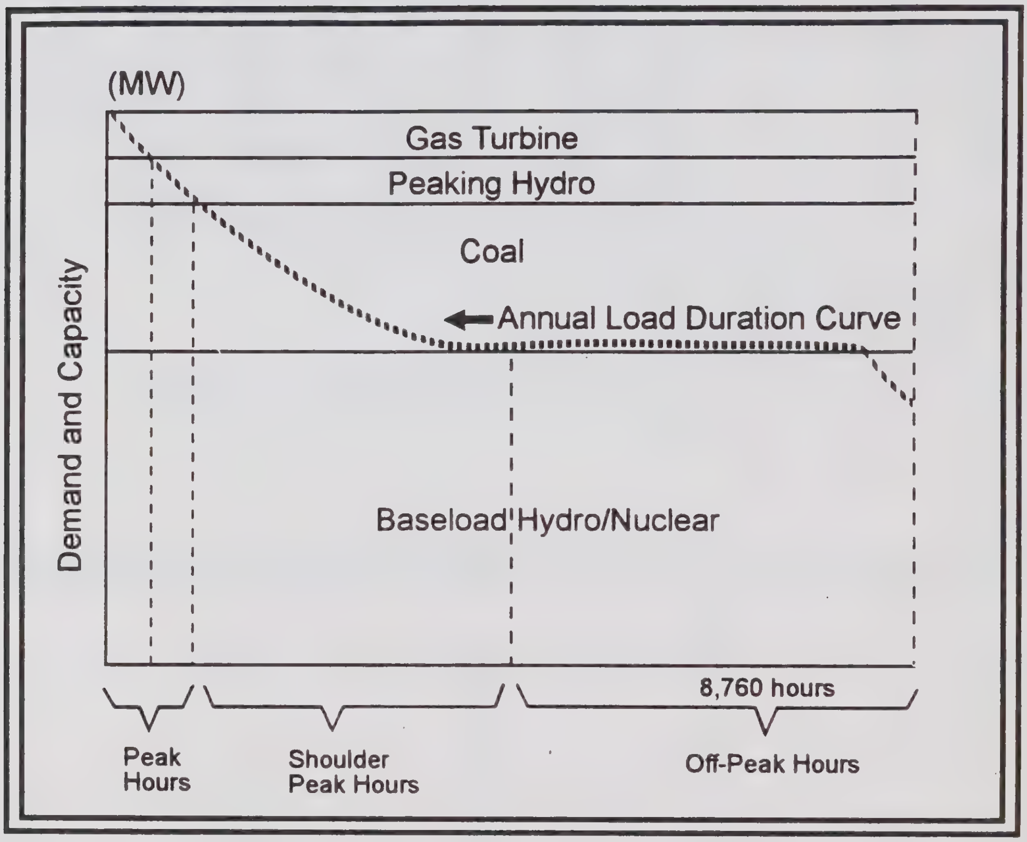
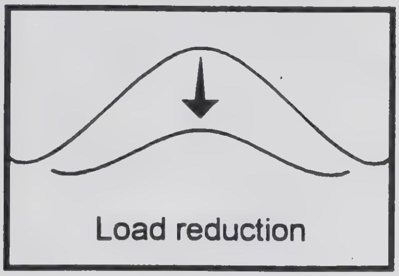
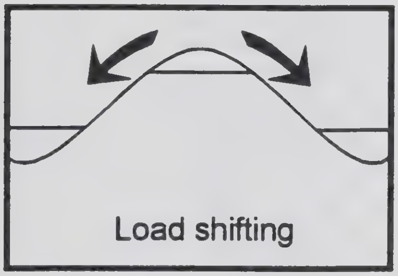


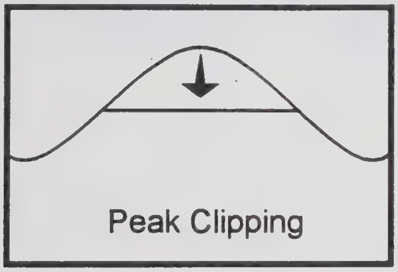
Figure 13.2 Demand-side Management Objectives and Programs



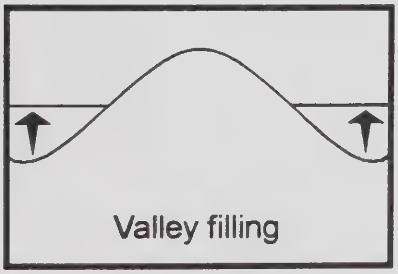
- improvements to end-use efficiency
- rate increases and restructuring



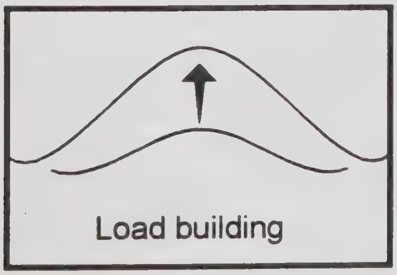
- time-of-use rates
- off-peak rates
- thermal energy storage
- direct load control



- time-of-use rates
- interruptible rates
- direct load control

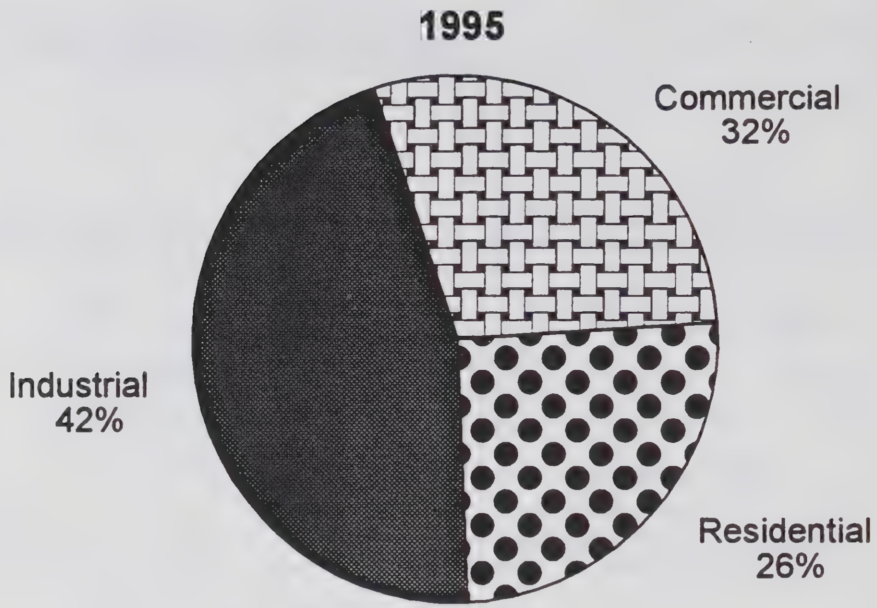


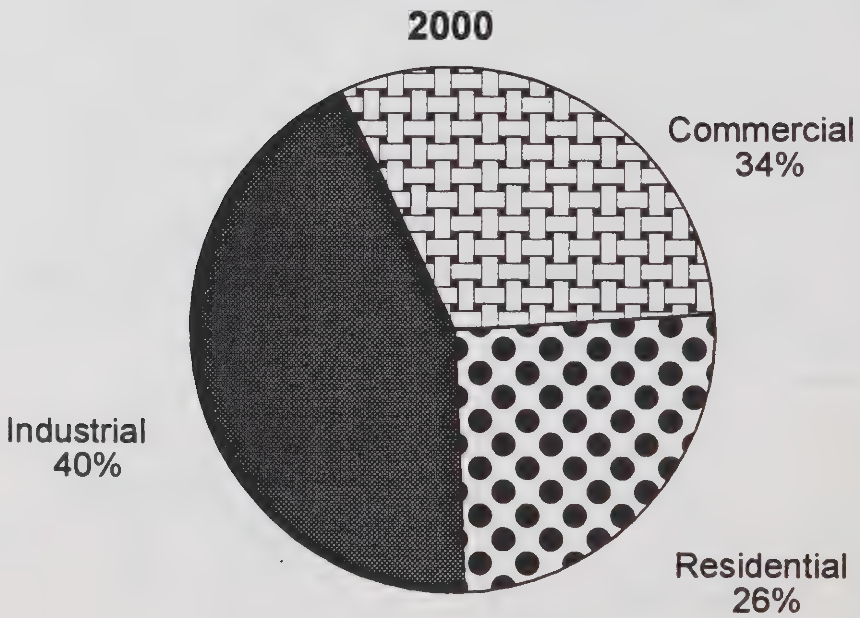
- time-of-use rates
- seasonal rates
- off-peak rates
- thermal energy storage



- promotional rates
- industrial electrotechnologies
- dual-fuel heating
- export marketing

Figure 13.3 Generating Capacity Savings by Sector due to DSM*





Non-Utility Generation

Traditional suppliers of electricity in Canada include investor-owned, provincial, municipal and territorial electric utilities. Minor utilities and large industry have also contributed to the supply of electricity. Over the past several years, however, environmental concerns, rising electricity rates, and growing international competition have led to a re-examination of alternative sources of electricity such as independent power producers (IPPs).

Non-utility generation (NUG) is defined here as electricity generation from facilities owned and operated by companies other than the major electric utilities reported in Table 1.1. In this chapter, non-utility generation consists of industrial establishments, minor utilities, and independent power production. This chapter examines the current contribution to electricity capacity and generation from NUG, the power purchase policies of the major utilities, and the future potential for NUG in Canada.

Current NUG Status

As of December 31, 1994, the total installed NUG capacity in service in Canada was estimated to be 8645 MW, or about 8 per cent of Canada's total generating capacity. Of this total, 6592 MW (76 per cent) was owned and operated by industrial establishments, mainly pulp and paper, mining, and aluminum smelting companies (Table 14.1). The remaining 2053 MW was owned by minor utilities (Table 14.2) and independent power producers (Table 14.3).

The largest share of installed NUG capacity is hydro, about 6099 MW or 71 per cent of the total. Natural gas contributed 1321 MW or 15 per cent of total NUG generation; waste fuels, including wood waste, flare gas, etc., contributed 1025 MW or 12 per cent; and oil contributed 200 MW or 2 per cent. NUG fuelled by natural gas, oil, wood waste, and flare gas was in the form of co-generation (i.e. generation producing electricity, and useable heat generally in the form of steam). This form of NUG capacity totalled 2578 MW in 1994. Of this total, about 38 per cent is located in Ontario, 28 per cent in Alberta, and 19 per cent in British Columbia.

It is estimated that a total of 54 991 GWh of electricity was generated by NUG facilities in 1994, accounting for 10.3 per cent of total Canadian electricity generation. Of this total, 43 360 GWh (79 per cent) was self-generation by large industry, and the remainder was generated by minor utility and independent power generators. (Tables 14.5 and 14.6). Of the total 54 991 GWh of non-utility generation, about 40 351 GWh (73 per cent) was hydroelectric, followed by natural gas with 9420 GWh (17 per cent), other generation with 4017 GWh (7 per cent) and oil with 1203 GWh (2 per cent).

Power Purchase Policies

Electricity supplied by a non-utility generator may be sold to a major electric utility or used to meet the producer's own electricity needs, i.e. self-generation. Although non-utility generators produced 54 991 GWh of electricity in 1994, it is estimated that only 8346 GWh (15 per cent) of this was sold to the major utilities. Ontario Hydro purchased about 5614 GWh, followed by B.C. Hydro (1284 GWh) and Hydro-Québec (265 GWh).

All major electric utilities have established policies concerning the purchase of electricity from NUG projects. Most utilities purchase electricity from non-utility generators at rates that reflect their long-term value to the power system. Appendix C summarizes power purchase rates of the major utilities across Canada for non-utility generation.

The following briefly outlines some NUG policies and developments in selected provinces.

Ontario Hydro has established the following policy elements for NUG: to remain committed to NUG as an essential part of future energy supply; to purchase electricity from non-utility generators at rates that reflect the costs Ontario Hydro would incur to generate the power; to purchase electricity from non-utility generators with power ratings of 5 MW or less through standard pre-approved rate schedules; and to purchase electricity from non-utility generators with power ratings greater than 5 MW through negotiation or by requests for proposals.

In Alberta, the provincial government passed the *Small Power Research and Development Act* (the Act) on May 11, 1988. The purpose of the Act is to facilitate the generation of electricity in Alberta through small projects using wind, hydro, and biomass resources, and to monitor production from small power projects. The results of the monitoring will allow Alberta to determine the contribution that small power projects can make to the province's electricity supply in the long term.

Under the Act, the purchase price for NUG projects is fixed at 5.2 cents per kWh until 1994, and the amount of power purchased at this price will be limited to 125 MW. The purchase contracts will be limited to between 15 and 25 years.

On October 15, 1992, the government of British Columbia announced its policy on the role of independent power producers in meeting domestic electricity needs. Acquisition of electricity from IPPs will be driven by domestic needs, and resources will be acquired according to their social costs. IPPs will not be invited to bid on hydro sites in basins already developed by B.C. Hydro, or on large hydro sites (in excess of 100 MW) in undeveloped basins that B.C. Hydro could efficiently develop. With respect to small power opportunities (under 5 MW), B.C. Hydro and the provincial government will identify areas where independent power developments would be appropriate and issue specific requests for proposals.

In British Columbia, all electricity generating resources acquisition will be evaluated on a social cost basis, and the final prices determined through competitive process. Social costs and benefits will be incorporated through an evaluation framework that includes recognition of the potential of NUG projects to reduce environmental problems and provide employ-ment opportunities in areas of high regional unemployment. In addition, POWEREX will assist the development of IPPs for export by providing technical and market expertise to the private sector. POWEREX will also facilitate arrangements for IPPs to deliver power to the export market.

Although Hydro-Québec has purchased electricity produced by industry for some time, Hydromega Development was the first independent power producer in Quebec to develop and operate small hydro generating stations expressly for the purpose of selling the output to Hydro-Québec. Hydromega owns and operates two hydro generating stations with installed capacities of 2.4 MW and 2.0 MW. Hydro-Québec purchases Hydromega's output at rates based on marginal costs. The term of the contract is 20 years.

In Saskatchewan, there are no NUG projects operating under contract to SaskPower. The province has 43 MW of installed cogeneration capacity ranging from 26 MW at the Weyerhaeuser pulp mill near Prince Albert, to a small unit at the North Battleford Hospital. These are self-generation projects which do not produce electricity for sale to SaskPower. However, SaskPower has indicated that proposals are being requested for 25 MW of NUG capacity for start-up in 1995. This request will allow SaskPower to gain experience with NUG.

As indicated in Appendix C, the power purchase rates of the major utilities are generally based on avoided-cost principles. As a result, the price of purchases of non-utility generation

should generally be equal to or less than the cost of future generation by the major utilities.

NUG Potential in Canada

This section presents the forecasts of the major electric utilities for non-utility generation expected to come into service over the planning period 1995-2010. The utilities have prepared the forecasts based in part on the economics of non-utility generation from the perspective of the NUG developer, and have taken into account the developers' equipment costs, fuel costs, and return on investment, as well as the projected purchase rates offered by the utilities.

Among the non-utility generators, IPPs are of great importance and interest to major utilities. The projections of NUG potential therefore concentrate mainly on IPPs. Table 14.7 summarizes the projections of IPPs' generating capacity for the period 1995-2010. According to major utilities' estimates, a total of 2787 MW of IPP capacity is attainable by the year 2000. Of this total, co-generation, fuelled mainly by natural gas, will account for 37 per cent, followed by other thermal (waste fuels) with 36 per cent, small hydro with 17 per cent and alternative sources with 10 per cent.

By 2000, it is projected that the majority of new independent power producers will be located in Ontario (57 per cent), British Columbia (16 per cent), and Quebec (13 per cent). By 2010, it is estimated that total attainable IPP capacity will decrease to 2771 MW. Other thermal and co-generation fuelled by natural gas will continue to supply the largest share of total IPPs in 2010 with 37 per cent each, followed by small hydro with 17 per cent and alternative sources with 9 per cent. It is also forecast that Ontario will continue to have the largest share of IPPs with 58 per cent of total independent power production in 2010.

The future development of NUG will depend on the profitability of NUG projects and the need for additional generating capacity. Achieving an acceptable rate of return on investment is a critical factor for non-utility generators. According to Ontario Hydro's estimates, rates of return on investment in the range of 15 to 20 per cent are required by a developer before a NUG project will be undertaken. The rate of return is linked to the purchase rate offered by the major utilities. With regard to the need for additional capacity, most of the major utilities will not require additional generating capacity for some years and thus may defer purchases from non-utility generators in the near term.

At present, the amount of electricity generated in Canada from non-utility generators is relatively small. However, in the past few years, electricity planners have begun to give NUG a much greater emphasis, especially where such generation is produced from renewable or waste resources, or at higher efficiencies than conventional generators. It is expected that NUG will play an increasingly important role in the development of Canada's electricity service in the next decade or two.

Tables are on the following pages.

Tables & Figures

Table 14.1
Industrial Installed Generating Capacity by Fuel Type, 1994

	Conventional Thermal							
	Coal	Oil	Gas	Sub-Total	Nuclear	Hydro	Other	Total
				(MW)				
Nfld.	0	3	0	3	0	78	0	81
P.E.I.	0	0	0	0	0	0	0	0
N.S.	0	29	0	29	0	5	18	52
N.B.	0	28	0	28	0	18	104	150
Quebec	0	22	24	46	0	2 780	5	2 831
Ontario	0	0	516	516	0	256	117	889
Manitoba	0	0	4	4	0	0	23	27
Sask.	0	22	37	59	0	0	22	81
Alberta	0	1	353	354	0	0	140	494
B.C.	0	77	51	128	0	1 305	528	1 961
Yukon	0	0	0	0	0	0	0	0
N.W.T.	0	3	20	23	0	3	0	26
Canada	**0**	**185**	**1 005**	**1 190**	**0**	**4 445**	**957**	**6 592**

Source: Electric Power Statistics, Volume III, Statistics Canada, catalogue 57-206 and Energy Supply Branch, Natural Resources Canada

Table 14.2
Minor Utility Installed Generating Capacity by Fuel Type, 1994

	Conventional Thermal							
	Coal	Oil	Gas	Sub-Total	Nuclear	Hydro	Other	Total
				(MW)				
Nfld.	0	0	0	0	0	134	0	134
P.E.I.	0	0	0	0	0	0	0	0
N.S.	0	0	0	0	0	0	0	0
N.B.	0	1	0	1	0	30	0	31
Quebec	0	0	0	0	0	638	0	638
Ontario	0	12	0	12	0	438	0	450
Manitoba	0	0	0	0	0	0	0	0
Sask.	0	0	0	0	0	0	0	0
Alberta	0	0	0	0	0	0	0	0
B.C.	0	0	0	0	0	211	0	211
Yukon	0	0	0	0	0	0	0	0
N.W.T.	0	0	0	0	0	0	0	0
Canada	**0**	13	**0**	13	**0**	**1 451**	**0**	**1 464**

Source: Electric Power Branch, National Energy Board, March 1995 and Energy Supply Branch, Natural Resources Canada, March 1995

Table 14.3
Independent Power Producer Installed Generating Capacity by Fuel Type, 1994

	Conventional Thermal							
	Coal	Oil	Gas	Sub-Total	Nuclear	Hydro	Other	Total
				(MW)				
Nfld.	0	0	0	0	0	0	0	0
P.E.I.	0	0	0	0	0	0	0	0
N.S.	0	0	0	0	0	0	0	0
N.B.	0	2	0	2	0	4	0	6
Quebec	0	0	77	77	0	40	0	117
Ontario	0	0	134	134	0	109	15	258
Manitoba	0	0	0	0	0	0	0	0
Sask.	0	0	0	0	0	0	0	0
Alberta	0	0	0	0	0	34	53	87
B.C.	0	0	105	105	0	16	0	121
Yukon	0	0	0	0	0	0	0	0
N.W.T.	0	0	0	0	0	0	0	0
Canada	**0**	**2**	**316**	**318**	**0**	**203**	**68**	**589**

Source: Electric Power Branch, National Energy Board, March 1995 and Energy Supply Branch, Natural Resources Canada, March 1995

Table 14.4
Industrial Energy Generation by Fuel Type, 1994

	Conventional Thermal							
	Coal	Oil	Gas	Sub-Total	Nuclear	Hydro	Other	Total
				(GWh)				
Nfld.	0	0	0	0	0	518	0	518
P.E.I.	0	0	0	0	0	0	0	0
N.S.	0	191	0	191	0	39	155	385
N.B.	0	366	0	366	0	52	273	691
Quebec	0	0	0	0	0	19 107	0	19 107
Ontario	0	0	1 750	1 750	0	1 437	190	3 377
Manitoba	0	6	12	18	0	0	54	72
Sask.	0	38	227	265	0	0	178	443
Alberta	0	0	3 384	3 384	0	0	1 115	4 499
B.C.	0	593	1 824	2 417	0	10 686	1 049	14 152
Yukon	0	0	0	0	0	0	0	0
N.W.T.	0	0	94	94	0	22	0	116
Canada	**0**	**1 194**	**7 291**	**8 485**	**0**	**31 861**	**3 014**	**43 360**

Source: Electric Power Statistics, Volume III, Statistics Canada, catalogue 57-206 and Energy Supply Branch, Natural Resources Canada

Table 14.5
Minor Utility Energy Generation by Fuel Type, 1994

	Conventional Thermal							
	Coal	Oil	Gas	Sub-Total	Nuclear	Hydro	Other	Total
				(GWh)				
Nfld.	0	0	0	0	0	880	0	880
P.E.I.	0	0	0	0	0	0	0	0
N.S.	0	0	0	0	0	0	0	0
N.B.	0	0	0	0	0	0	0	0
Quebec	0	0	0	0	0	3 727	0	3 727
Ontario	0	1	0	1	0	1 829	0	1 830
Manitoba	0	0	0	0	0	0	0	0
Sask.	0	0	0	0	0	0	0	0
Alberta	0	0	0	0	0	0	0	0
B.C.	0	0	0	0	0	1 127	0	1 127
Yukon	0	0	0	0	0	0	0	0
N.W.T.	0	0	0	0	0	0	0	0
Canada	**0**	**1**	**0**	**1**	**0**	**7 563**	**0**	**7 564**

Source: Electric Power Branch, National Energy Board, March 1995, and Energy Supply Branch, Natural Resources Canada, March 1995

Table 14.6
Independent Power Producer Energy Generation by Fuel Type, 1994

	Conventional Thermal							
	Coal	Oil	Gas	Sub-Total	Nuclear	Hydro	Other	Total
				(GWh)				
Nfld.	0	0	0	0	0	0	0	0
P.E.I.	0	0	0	0	0	0	0	0
N.S.	0	0	0	0	0	0	0	0
N.B.	0	8	0	8	0	21	0	29
Quebec	0	0	0	0	0	174	0	174
Ontario	0	0	1 611	1 611	0	344	377	2 332
Manitoba	0	0	0	0	0	0	0	0
Sask.	0	0	0	0	0	0	0	0
Alberta	0	0	0	0	0	195	181	376
B.C.	0	0	518	518	0	193	445	1156
Yukon	0	0	0	0	0	0	0	0
N.W.T.	0	0	0	0	0	0	0	0
Canada	**0**	**8**	**2 129**	**2 137**	**0**	**927**	**1 003**	**4 067**

Source: Electric Power Branch, National Energy Board, March 1995 and Energy Supply Branch, Natural Resources Canada, March 1995.

Table 14.7
Projections of Attainable Independent Power Producer Generating Capacity

	1995	2000				2010			
		Hydraulic	Cogeneration	Other Thermal	Alternatives	Hydraulic	Cogeneration	Other Thermal	Alternatives
	(MW)								
Nfld.	0	38	0	0	0	38	0	0	0
N.S.	7	4	22	8	11	4	21	4	11
N.B.	10	4	0	2	50	4	0	2	50
Quebec	234	192	30	0	148	192	30	0	110
Ontario	1 011	149	834	614	0	149	834	614	0
Sask.	60	0	100	0	3	0	135	15	13
Alberta	134	49	33	0	60	49	0	0	60
B.C.	200	46	0	390	0	46	0	390	0
Canada	**1 656**	**482**	**1 019**	**1 014**	**272**	**482**	**1 020**	**1 025**	**244**

Source: Canadian electric utilities, March 1995

Table 14.8
Projections of Attainable Independent Power Producer Generation

	1995	2000				2010			
		Hydraulic	Cogeneration	Other Thermal	Alternatives	Hydraulic	Cogeneration	Other Thermal	Alternative
	(GWh)								
Nfld.	0	218	0	0	0	218	0	0	0
N.S.	31	25	171	65	81	25	168	33	82
N.B.	74	25	0	11	361	25	0	11	361
Quebec	1145	1372	227	0	1107	1 368	226	0	923
Ontario	6517	655	5802	4589	0	655	5 802	4 589	0
Sask.	420	0	700	0	6	0	950	100	30
Alberta	548	200	116	0	385	200	0	0	385
B.C.	1700	508	0	3172	0	508	0	3 171	0
Canada	**10435**	**3003**	**7016**	**7837**	**1940**	**2 999**	**7 146**	**7 904**	**1781**

Source: Canadian electric utilities, March 1995

Installed Generating Capacity, Production and Electricity Trade

Table A1.
Installed Capacity and Electrical Energy Consumption in Canada, 1920-1994

	INSTALLED CAPACITY										
	Thermal										
Year	Conventional	Nuclear	Sub-total	Hydro	Total	Electrical Energy Consumption	Average Demand	Peak Demand	Reserve Margin		Load Factor
	(MW)					(GWh) (a)	(MW) (b)	(MW) (c)	(MW) (d)	(%)	(%) (e)
1920	300	-	300	1 700	2 000	-	-	-	-	-	-
1930	400	-	400	4 300	4 700	19 468	2 222	-	-	-	-
1940	500	-	500	6 200	6 700	33 062	3 774	-	-	-	-
1950	900	-	900	8 900	9 800	55 037	6 283	-	-	-	-
1955	2 100	-	2 100	12 600	14 700	81 000	9 247	12 536	2 164	17	74
1960	4 392	-	4 392	18 643	23 035	109 304	12 478	17 264	5 771	33	72
1965	7 557	20	7 577	21 771	29 348	144 165	16 457	24 167	5 181	21	68
1970	14 287	240	14 527	28 298	42 826	202 337	23 098	34 592	8 234	24	67
1975	21 404	2 666	24 070	37 282	61 352	265 955	30 360	46 187	15 165	33	66
1980	28 363	5 866	34 229	47 770	81 999	340 068	38 821	59 167	22 832	39	66
1981	28 493	5 600	34 093	49 216	83 308	346 333	39 536	59 237	24 071	41	67
1982	28 957	6 547	35 504	50 007	85 511	345 115	39 397	62 417	23 094	37	63
1983	30 447	7 771	38 218	51 274	89 492	359 838	41 077	66 866	22 626	34	61
1984	30 427	9 813	40 240	54 949	95 189	385 516	44 009	65 798	29 391	45	67
1985	30 475	10 664	41 139	55 880	97 019	406 859	46 445	71 235	25 784	36	65
1986	30 979	11 364	42 343	57 731	100 074	423 027	48 153	70 364	29 710	42	68
1987	30 800	12 528	43 328	57 945	101 273	439 710	50 195	77 923	23 350	30	64
1988	30 525	12 593	43 118	57 937	101 055	462 948	52 848	78 961	22 094	28	67
1989	30 892	12 603	43 495	58 465	101 960	474 358	53 971	78 200	23 760	30	69
1990	31 173	13 052	44 225	58 722	102 947	465 395	53 127	78 302	24 645	31	68
1991	32 101	13 052	45 153	60 271	105 424	474 597	54 178	82 963	22 461	27	65
1992	32 720	13 987	46 707	61 993	108 700	476 538	54 399	82 330	26 370	32	66
1993	33 765	16 393	50 158	62 047	112 205	484 291	55 284	86 040	26 165	30	64
1994	34 250	16 393	50 643	63 234	113 877	490 776	56 025	90 081	23 796	26	62

(a) 1920-55: Figures are approximate, computed using actual statistics Canada data for stations generating energy for sale to which have been added estimates for stations generating entirely for own use. 1920-55: Canadian Energy Prospects (Royal Commision on Canada's Economic Prospects), John Davis, 1957. 1956-81: Statistics Canada Publication 57-202

(b) Average Demand = Energy Consumption/8760 (hrs/yr).

(c) Statistics Canada Publication, 57-204.

(d) Reserve Margin = (Installed Capacity - Peak Demand) ÷ Peak Demand

(e) Load Factor = Average Demand/Peak Demand

Source: Statistics Canada and Department of Natural Resources Canada

Table A2.
Installed Generating Capacity, 1994

	Hydro	Nuclear	Conventional Thermal	Total	% of Canadian Total
	....	....	(MW)	....	
Newfoundland	6 650	0	803	7 453	6.54
P.E.I.	0	0	121	121	0.11
Nova Scotia	390	0	1 924	2 314	2.03
New Brunswick	903	680	2 795	4 378	3.84
Quebec	30 581	685	1 640	32 906	28.90
Ontario	7204	15 028	14 341	36 573	32.12
Manitoba	4 498	0	413	4 911	4.31
Saskatchewan	836	0	2 243	3 079	2.70
Alberta	823	0	7 964	8 787	7.72
British Columbia	11 223	0	1 786	13 009	11.42
Yukon	77	0	57	134	0.12
N.W.T.	49	0	163	212	0.19
Canada *(totals as of Dec. 31/94)*:	63 234	16 393	34 250	113 877	100.00
Percentage Total:	55.53	14.40	30.07	100.00	
Net Additions during 1994	1266	0	406	1 672	

Source: Department of Natural Resources Canada

Table A3.
Conventional Thermal Capacity by Principal Fuel Type, 1994* (MW)

Steam					
	Coal	Oil	Gas	Other	Total
Newfoundland	0	520	0	5	525
P.E.I.	0	69	0	0	69
Nova Scotia	1 317	383	0	19	1 719
New Brunswick	808	1 342	0	104	2 254
Quebec	0	615	8	5	628
Ontario	10 653	2 200	438	132	13 423
Manitoba	369	0	4	23	396
Sask.	1 766	21	278	22	2 088
Alberta	5 987	0	1 251	193	7 431
British Columbia	0	63	961	528	1 552
Yukon	0	0	0	0	0
N.W.T.	0	0	0	0	0
Canada	**20 900**	**5 212**	**2 940**	**1 030**	**30 082**

Gas Turbine			
	Oil	Gas	Total
Newfoundland	197	0	197
P.E.I.	40	0	40
Nova Scotia	205	0	205
New Brunswick	525	0	525
Quebec	791	93	884
Ontario	506	395	901
Manitoba	0	0	0
Sask.	0	155	155
Alberta	0	500	500
British Columbia	100	46	146
Yukon	0	0	0
N.W.T.	5	20	25
Canada	**2 369**	**1209**	**3 578**

** Preliminary figures as of December 31, 1994.*
(Numbers may not total due to rounding).

Table A3. continued

Internal Combustion			
	Oil	Gas	Total
Newfoundland	81	0	81
P.E.I.	11	0	11
Nova Scotia	2	0	2
New Brunswick	16	0	16
Quebec	128	0	128
Ontario	4	13	17
Manitoba	17	0	17
Sask.	1	0	1
Alberta	19	15	34
British Columbia	64	24	89
Yukon	58	0	58
N.W.T.	138	0	138
Canada	**538**	**52**	**590**

All Conventional Thermal					
	Coal	Oil	Gas	Other*	Total
Newfoundland	0	798	0	5	803
P.E.I.	0	121	0	0	121
Nova Scotia	1 317	589	0	19	1 925
New Brunswick	808	1 883	0	104	2 795
Quebec	0	1 534	101	5	1 640
Ontario	10 653	2 709	846	132	14 341
Manitoba	369	17	4	23	413
Sask.	1 766	22	433	22	2 243
Alberta	5 987	19	1 766	193	7 964
British Columbia	0	227	1 031	528	1 786
Yukon	0	58	0	0	58
N.W.T.	0	143	20	0	163
Canada	**20 900**	**8 119**	**4 201**	**1030**	**34 250**

** Mainly wood wastes and black liquor.*

Source: Electricity Branch, Natural Resources Canada

Table A4.
Electrical Energy Production by Principal Fuel Type, 1994 (GWh)

	Conventional Thermal*							
	Coal	Oil	Gas	Sub-total	Nuclear	Hydro	Other	Total
Newfoundland	0	867	0	867	0	37 538	0	38 405
P.E.I.	0	40	0	40	0	0	0	40
Nova Scotia	7 160	1 397	0	8 557	0	1 048	155	9 760
New Brunswick	5 273	2 071	0	7 344	5238	2 741	544	15 867
Quebec	0	317	0	317	5 406	157 176	0	162 899
Ontario	14 873	156	3 361	18 390	91 086	38 390	567	148 433
Manitoba	206	6	23	235	0	28 146	54	28 435
Sask.	11 214	47	639	11 900	0	3 393	178	15 471
Alberta	42 478	83	6 629	49 190	0	1 809	1 296	52 295
British Columbia	0	793	4 749	5 542	0	53 979	1 494	61 015
Yukon	0	36	0	36	0	261	0	297
N.W.T.	0	292	94	386	0	205	0	591
Canada	**81 204**	**6 105**	**15 495**	**102 804**	**101 730**	**324 686**	**4 288**	**533 508**

	Percentage of Total Generation	Percentage Generated by Utilities	Percentage Generated by Industry
Newfoundland	7.20	98.65	1.35
P.E.I.	0.01	100.00	.00
Nova Scotia	1.83	96.06	3.94
New Brunswick	2.97	95.55	4.35
Quebec	30.53	88.27	11.73
Ontario	27.82	97.72	2.28
Manitoba	5.33	99.75	0.25
Sask.	2.90	97.14	2.86
Alberta	9.80	91.40	8.60
British Columbia	11.44	76.81	23.19
Yukon	0.06	100.00	.00
N.W.T.	0.11	80.37	19.63
Canada	**100.00**	**91.87**	**8.13**

** The conventional thermal breakdown is estimated.*
Source: Statistics Canada and Department of Natural Resources Canada

Table A5.
Provincial Electricity Imports and Exports (GWh), 1989-1994

		Interprovincial Trade			International Trade*			
Province	Year	Exports	Import	Net Exports	Exports	Imports	Net Exports	Total Net Exports
Newfoundland	1994	27 446		27 446				27 446
	1993	29 942	-	29 942	-	-	-	29 942
	1992	25 985	-	25 985	-	-	-	25 985
	1991	26 366	-	26 366	-	-	-	26 366
	1990	26 164	-	26 164	-	-	-	26 164
	1989	24 367	-	24 367	-	-	-	24 367
Prince Edward Island	1994		776	-776				-776
	1993	-	747	-747	-	-	-	-747
	1992	-	738	-738	-	-	-	-738
	1991	-	690	-690	-	-	-	-690
	1990	-	672	-672	-	-	-	-672
	1989	-	622	-622	-	-	-	-622
Nova Scotia	1994	46	260	-214				-214
	1993	42	248	-199	-	-	-	-199
	1992	67	253	-186	-	-	-	-186
	1991	50	444	-394	-	-	-	-394
	1990	116	365	-249	-	-	-	-249
	1989	341	441	-100	-	-	-	-100
New Brunswick	1994	1 684	2 174	-490	2 340	142	2 198	1 708
	1993	1 032	1 509	-477	1 837	121	1 716	1 452
	1992	4 345	3 925	420	1775	116	1 659	2075
	1991	2 542	3 433	-891	3 092	79	3 013	2 122
	1990	2 153	2 775	-622	4 277	162	4 115	3 493
	1989	2 014	2 307	-293	4 640	264	4 376	4 083
Quebec	1994	3 592	28 897	-25 305	17 337	1 304	16 033	-9 272
	1993	2 486	30 519	-28 033	13 009	684	12 325	-16 262
	1992	4 509	29 527	-25 018	8 877	1 388	7 489	-17 529
	1991	4 112	27 883	-23 771	5 959	730	5 229	-18 542
	1990	3 349	27 414	-24 065	3 403	1 188	2 215	-21 851
	1989	2 998	25 399	-22 401	5 438	1 001	4 437	-17 964

Table A5. continued

Province	Year	Interprovincial Trade Exports	Interprovincial Trade Import	Interprovincial Trade Net Exports	International Trade* Exports	International Trade* Imports	International Trade* Net Exports	Total Net Exports
Ontario	1994	858	1 842	-984	13 373	1 387	11 986	11 002
	1993	555	1 897	-1 342	7 157	2 590	4 567	3 225
	1992	201	2 203	-2 002	5 303	4 166	1 137	-865
	1991	109	2 211	-2 102	4 771	3 674	1 097	-1 005
	1990	140	2 326	-2 186	2 050	13 339	-11 289	-13 475
	1989	91	2 335	-2 244	4 314	7 864	-3 550	-5 794
Manitoba	1994	1 914	1 004	910	8 665	42	8 623	9 533
	1993	2 240	924	1 316	7 359	196	7 163	8 479
	1992	3 113	965	2 148	6 250	11	6 239	8 387
	1991	2 634	975	1 659	3 478	289	3 189	4 848
	1990	2 694	1 053	1 641	2 050	991	1 059	2 700
	1989	2 474	1 126	1 348	1 284	1 447	-163	1 185
Saskatchewan	1994	1 125	1 515	-390	62	128	-66	-456
	1993	1 330	1 388	-58	229	147	82	-24
	1992	1 083	1 584	-501	138	100	38	-463
	1991	998	1 268	-270	148	120	28	-242
	1990	1 086	1 152	-66	121	107	14	136
	1989	1 130	1 213	-83	72	123	-51	-134
Alberta	1994	2 586	486	2 103	-	3	-3	2 100
	1993	2 088	769	1 319	-	2	-2	1 204
	1992	2 016	399	1 617	-	2	-2	1 596
	1991	1 064	678	386	-	3	-3	383
	1990	1 336	500	836	-	3	-3	833
	1989	2 519	258	2 261	-	3	-3	2 258
British Columbia	1994	307	2 561	-2 254	9 234	5 274	3 960	1 706
	1993	348	2 062	-1 714	5 256	3 629	1 627	-87
	1992	267	1 993	-1 726	9 206	692	8 514	6 788
	1991	655	948	-293	7 070	1 324	5 746	5 453
	1990	461	1 242	-781	6 228	1 991	4 237	3 456
	1989	242	2 477	-2 235	6 341	2 024	4 317	2 082

Table A5. continued

Province	Year	Interprovincial Trade Exports	Interprovincial Trade Imports	Interprovincial Trade Net Exports	International Trade* Exports	International Trade* Imports	International Trade* Net Exports	Total Net Exports
Yukon	1994							
	1993	-	-	-	-	-	-	-
	1992	-	-	-	-	-	-	-
	1991	-	-	-	-	-	-	-
	1990	-	-	-	-	-	-	-
	1989	-	-	-	-	-	-	-
Northwest Territories	1994							
	1993	-	-	-	-	-	-	-
	1992	-	-	-	-	-	-	-
	1991	-	-	-	-	-	-	-
	1990	-	-	-	-	-	-	-
	1989	-	-	-	-	-	-	-
Canada	1994				51 012	8 280	42 732	42 732
	1993	-	-	-	34 848	7 370	27 478	27 478
	1992				31 549	6 476	25 073	25 073
	1991	-	-	-	24 518	6 219	18 299	18 299
	1990	-	-	-	18 130	17 781	349	349
	1989	-	-	-	22 089	12 724	9 365	9 365

** Includes exchanges.*

Source: National Energy Board

Table A6.
Canadian Electricity Exports by Exporter and Importer, 1994*

EXPORTER	IMPORTER	Revenue ($ 000)	Quantity (GWh)
Fraser Inc.	Fraser Paper Ltd. (Maine)	19 279	323
Maine & New Brunswick Electrical Power Co. Ltd.	Maine Public Service Co. (Maine)	2 476	89
NB Power	Houlton Water Co. (Maine)	280	4
NB Power	Maine Public Service Co. (Maine)	5 279	182
NB Power	Eastern Maine Electric Cooperative Inc. (Maine)	5 579	87
NB Power	Maine Electric Power (Maine)	30 615	1 088
NB Power	Bangor Maine (Maine)	6 654	234
Hydro-Québec	Vermont Joint Owners (Vermont)	67 885	1 131
Hydro-Québec	Vermont Dept. of Public Service (Vermont)	33 226	855
Hydro-Québec	Central Vermont Public Utilities (Vermont)	1 116	51
Hydro-Québec	Citizens Utilities (Vermont)	888	31
Hydro-Québec	Green Mountain Power (Vermont)	1 023	42
Hydro-Québec	New England Power Pool (New England)	166 321	6 972
Hydro-Québec	Niagara Mohawk Power Corp. (New York)	52 732	3 230
Hydro-Québec	New York Power Authority (New York)	140 414	5 024
Canadian Niagara	Niagara Mohawk Power Corp. (New York)	5 394	393
Cornwall Electric	Niagara Mohawk Power Corporation(New York)	415	23
Ontario Hydro	Vermont Dept. of Public Service (Vermont)	1 942	85
Ontario Hydro	Niagara Mohawk Power Corp. (New York)	6 791e	230
Ontario Hydro	New York Power Authority (New York)	93 365	3 485
Ontario Hydro	New York Power Pool (New York)	1 640	502
Ontario Hydro	Long Island Lighting (New York)	593	22
Ontario Hydro	Northeast Utilities (Michigan)	2 481	104
Ontario Hydro	Consolidated Edison (Michigan)	40 550	1 271
Ontario Hydro	Detroit Edison Co. (Michigan)	189 070	6 909
Ontario Hydro	Minnesota Power and Light	1 906	76
Ontario Hydro	New England Power Co. (Massachusetts)	350	15
Ontario Hydro	Central Vermont Public Utilities (Vermont)	2 184	111
Ontario Hydro	Rochester Gas and Electric (New York)	449	5
Ontario Hydro	Pennsylvania General Public Utilities (PA)	4 261	141
Manitoba Hydro	Northern States Power Co. (Minnesota)	229 583	6 380
Manitoba Hydro	Otter Tail Power Co. (Minnesota)	14 835	685
Manitoba Hydro	United Power Association (Minnesota)	319	25
Manitoba Hydro	Minnesota Power & Light Co. (Minnesota)	14 554	757
Manitoba Hydro	Minnkota Power Cooperative Inc. (North Dakota)	21 366	1 074
Sask. Power	Basin Electric Power Cooperative (North Dakota)	431	62
Cominco Ltd.	Pacific Corp. (Washington)	35	1
Cominco Ltd	Washington Water Power Co. (Washington)	9	0.3
Cominco Ltd.	Bonneville Power Administration (Washington)	1 374	48
Cominco Ltd.	Portland General Electric Co. (Oregon)	296	11
Cominco Ltd.	Idaho Power (Idaho)	213	6
B.C. Hydro	Idaho Power (Idaho)	2 072	61
B.C. Hydro	Seattle City Light (Washington)	8 271	263
B.C. Hydro	Puget Sound Power & Light Co. (Washington)	1 114	24
B.C. Hydro	Washington Water Power Co. (Washington)	715	21

Table A6. continued

EXPORTER	IMPORTER	Revenue ($ 000)	Quantity (GWh)
B.C. Hydro	Bonneville Power Administration (Washington)	89 656	7 551
B.C. Hydro	Hetch Hetchy Water (washington)	436	45
B.C. Hydro	Sierra Pacific Power Co. (Washington)	14	0.4
B.C. Hydro	Snohomism PUD (Washington)	127	5
B.C. Hydro	Pacific Corp. (Washington)	1 656	48
B.C. Hydro	Tacoma City Light (Washington)	64	2
B.C. Hydro	Portland General Electric Co. (Oregon)	42 803	1 056
B.C. Hydro	City of Riverside (California)	193	11
B.C. Hydro	North California Power (California)	798	26
B.C. Hydro	Pacific Gas & Electric (California)	2 631	93
B.C. Hydro	Southern California Edison (California)	308	9
B.C. Hydro	Hetch Hetchy Water (California)	105	5
B.C. Hydro	Sacramento Municipal Utilities District (California)	83	3
B.C. Hydro	Western Area Power (California)	12	0.3
B.C. Hydro	Nevada Power Co. (Nevada)	233	7

* *Excludes border accommodations*

Source: National Energy Board

Table A7.
Proposed Generating Capacity Expansion in Canada by Station: Major 1994 Additions

Province and Station	Type*	1994 Additions	Completion Date	Additions Proposed	Status*	Plant Capacity
		(MW)		(MW)		(MW)
NEWFOUNDLAND						
Rose Blanche	H		1997	6	p	6
PRINCE EDWARD ISLAND						
Charlottetown	GT(o)		2002	24	P	24
NOVA SCOTIA						
Point Aconi	S(c)		1995	165	C	
Point Aconi	S(c)		2005	165	P	
Point Aconi	S(c)		2009	165	P	495
New	S(o)		2004	170	P	170
New	GT(o)		2007	100	P	100
Glace Bay	S(c)		2004	117	P	117
NEW BRUNSWICK						
Belledune	S(c)		2006	440	P	
			2008	440	P	1 283
Combustion Turbine	GT(o)		2001	100	P	100
Combustion Turbine	GT(o)		2004	100	P	100
Combustion Turbine	GT(o)		2005	100	P	100
Combustion Turbine	GT(o)		2008	100	P	100
Combustion Turbine	GT(o)		2009	100	P	100
QUEBEC						
La Forge-1	H	543				
Manic-5♦	H	67				
LG-1	H	656				
La Forge-2	H		1996	145	C	
			1996	144	C	289
Manic-2	H		2002	320	P	1 376
Manic-3	H		2001	2 x 300	P	1 803

♦ *Uprating of existing units*

Table A7.
Proposed Generating Capacity Expansion in Canada by Station: Major 1994 Additions (continued)

Province and Station	Type*	1994 Additions	Completion Date	Additions Proposed	Status*	Plant Capacity
		(MW)		(MW)		(MW)
QUEBEC (cont'd)						
Outardes 4	H		2003	350	P	350
Outardes 3	H		2003	2 x 240	P	480
Outardes 2	H		2003	280	P	280
LG-1			1995	3 x 113	C	
			1995	3 x 112	C	675
Ste-Marguerite-3	H		2001	2 x 414	C	828
Grande-Baleine-1	H		2002	2 x 411	P	
			2002	412	P	
			2002	2 x 412	P	2 058
Grande-Baleine-2	H		2003	3 x 180	P	540
Grande-Baleine-3	H		2003	187	P	
			2004	188	P	
			2004	185	P	560
Eastmain-1	H		1999	3 x 155	P	465
Lac Robertson	H		1995	2 x 10.5	C	21
Ashuapmushuan-4	H		2004	730	P	730
Mercier	H		2000	100	P	100
Kipawa	H		2002	115	P	115
Haut-Saint-Maurice	H		2002	615	P	615
ONTARIO						
NONE						
MANITOBA						
Wuskwatim	H		2011	2 x 85	P	
			2012	2 x 85	P	340
SASKATCHEWAN						
NONE						

Table A7.
Proposed Generating Capacity Expansion in Canada by Station: Major 1994 Additions (continued)

Province and Station	Type*	1994 Additions	Completion Date	Additions Proposed	Status*	Plant Capacity
		(MW)		(MW)		(MW)
ALBERTA						
Genesee	S(c)	406				
BRITISH COLUMBIA						
Seven Mile 4	H		2000	196	P	785
Waneta	H		2003	2 x 190	P	380
Keeneleyside	H		2006	3 x 80	P	240
Brilliant	H		2009	73	P	
	H		2010	75	P	450
Revelstoke	H		2000	450	C	
	H		2004	450	P	900
Mica	H		2005	400	P	
	H		2009	400	P	800
YUKON						
McIntyre	H	0.8				
NORTHWEST TERRITORIES						
Arctic Bay	IC		1995	0.5	P	
	IC		1995	0.4	P	
Lac La Martre	IC		1995	0.5	P	
Pangnirtung	IC		1995	1.4	P	
Fort McPherson	IC		1995	0.8	P	
Fort Norman	IC		1996	0.5	P	
Snare Rapids	H		1996	0.4	P	
Snare Cascades	H		1997	4.2	P	

***Legend**

H	Hydro	IC	Internal combustion
S(c)	Steam (coal)	GT	Gas turbine
N	Nuclear	I	Installed
P	Planned	C	Under construction
GT(o)	Gas turbine (oil)		
GT(g)	Gas turbine (natural gas)		

Source: Natural Resources Canada

Federal Environmental Standards and Guidelines

Recent amendments to the National Energy Board Act specify that the Board, in assessing applications for exports and international transmission lines, consider the potential impacts of projects on the environment. (See Chapter 3 for a detailed discussion of the regulatory process.) This appendix provides a brief overview of some federal environmental standards that, in addition to provincial environmental protection measures, may be particularly relevant to the assessment of such impacts.

Federal environmental standards are those that have been authorized or endorsed by the federal government and that apply where a project affects an area of explicit federal jurisdiction, such as navigable waters or migratory birds. Following a general discussion of types of environmental standards, the relevant federal standards are summarized briefly.[1]

Types of Environmental Standards

Environmental standards are norms established with the overall objective of protecting both human and environmental health. For the purposes of this report, the term "environmental standards" will be used as a general reference to all environmental guidelines, objectives, limits, criteria and codes of practice. Federal environmental standards are grouped into three general categories for the purposes of discussion: ambient standards, emission standards and other standards.

[1] *Greater detail on federal legislation, initiatives and standards may be obtained by contacting the Electricity Branch, Department of Natural Resources Canada.*

Ambient Standards

Ambient standards are quantitative or qualitative statements describing a level of environmental quality that, if maintained in the "ambient" or open environment, will normally protect environ-mental and human health. Such standards generally specify concentrations of substances, or physical characteristics such as water temperature. Federal ambient standards normally have no legal force in themselves. They describe a level of environmental quality that may apply to specific designated regions, or to all regions of Canada. They serve as the goals or objectives towards which pollution-control initiatives, including legislation and regulations specifying emission standards, are directed.

Emission Standards

Emission standards refer to a limit on the quantity or quality of substances that may be released from industrial processes. They usually specify a release rate or maximum concentration of a harmful substance that may be present in the emission as it emerges from its source: a smokestack, pipeline or landfill drainage system. Federal emission standards, which are given force of law under regulations, are considered to be the minimum acceptable requirements for any industrial undertaking. More stringent emission standards may be required to meet appropriate ambient standards at a particular site.

Other Standards

Other standards include programs and legislation that provide for a wide variety of environmental protection measures, in addition to ambient or emission standards. Examples include the Environmental Codes of Practice for Steam Electric Power Generation and the Canadian Environmental Protection Act.

Overview of Federal Standards

1.1 Ambient Standards: Air

National Ambient Air Quality Objectives

The *National Ambient Air Quality Objectives*, published under the authority of the Canadian Environmental Protection Act (CEPA) of 1988, specifies criteria for tolerable, acceptable and desirable levels of sulphur dioxide, nitrogen oxides, particulate matter, ozone and carbon monoxide in the open or ambient atmosphere.

Intergovernmental Agreements

Ambient standards are one method of implementing intergovernmental agreements to reduce and control air pollution. (For a general discussion of intergovernmental agreements on air pollution, see section 3.3 of this appendix.)

1.2 Ambient Standards: Water

Water Quality Guidelines

The Canadian Water Quality Guidelines, published by the Canadian Council of Ministers of the Environment (CCME), is an inventory of "water quality objectives" (ambient standards) suitable for different water uses in Canada, such as aquatic life, industrial processes, human consumption, recreational use and agricultural irrigation. These standards differ depending on the different water uses and must therefore be adapted to meet regional water quality needs. These standards are developed from existing guidelines where appropriate, such as the *Guidelines for Canadian Drinking Water Quality*, established by the Federal-Provincial Subcommittee on Drinking Water.

Intergovernmental Agreements

Canada has entered into an agreement with the United States (The Great Lakes Water Quality Agreement) to restore and maintain the water quality of the Great Lakes basin. To assist in meeting the goals of the Agreement, environmental quality objectives (ambient standards) were established for these waters.

Other regional ambient standards may be developed under federal-provincial agreements and programs enacted pursuant to the Canada Water Act.

2.1 Emission Standards: Air

Thermal Power Generation Emissions – National Guidelines for New Stationary Sources

These guidelines, published under the authority of CEPA, and revised in 1993, are technology-based air emission standards for new fossil-fuelled electric generating stations. They are generic emission limitations recommended as minimum national standards that should be adopted by utilities and provincial governments. Criteria specified in the guidelines include those for sulphur dioxide, nitrogen oxides and particulate matter emissions, as well as for opacity (visibility standards) and continuous emission monitoring.

2.2 Emission Standards: Water

The Environmental Codes of Practice for Steam Electric Power Generation

See Other Federal Standards, section 3.1, for a general description of the Codes of Practice.

The Design Phase Code of Practice recommends technology-based minimum waste water emission limitations. These standards specify effluent criteria for metals, oil and grease, chlorine, suspended solids and acidity, to minimize the total amount of contaminants discharged to surface waters. These criteria are of concern to aquatic and human life.

Federal Legislation: the Fisheries Act, the Canada Water Act, and the Migratory Birds Act

The Fisheries Act prohibits the deposit of deleterious substances in any waters inhabited by fish. Regulations may limit the deposit of certain types of waste or substances in specific quantities and concentrations. Provisions are supported by Environment Canada's *Environmental Codes of Practice for Steam Electric Power Generation*. The Act also includes a broad range of environmental protection measures that cannot be adequately discussed in this short summary.

The Canada Water Act provides the federal government with the authority to regulate the emission of substances in designated "water quality management" areas. No regulations for water emissions have been implemented under this Act. The Act also provides the federal government with the authority to enter agreements with the provinces for water quality management.

Regulations pursuant to the Migratory Birds Act prohibit, in certain circumstances, the dumping of substances harmful to migratory birds in any water or area populated by these birds in Canada.

Other Federal Standards

3.1 Environmental Codes of Practice for Steam Electric Power Generation

The *Environmental Codes of Practice*, developed by a federal-provincial government and industry task force established by Environment Canada, contain recommendations judged to be reasonable and practical measures that can be taken to preserve the quality of the environment affected by fossil- and nuclear-fuelled electric power generation. Codes of practice have been published for the design, siting, construction, operation and decommissioning phases of steam electric power generation projects. Although the design and siting phase codes have no legal status, the construction, operation and decommissioning phase codes have been published under the authority of CEPA.

The various phases of the codes of practice, although treated in separate documents, are interdependent. To ensure environmental protection throughout the life of a steam electric power generating facility, the Codes should be considered as a whole.

3.2 Federal Legislation for the Control of Harmful Substances

The Canadian Environmental Protection Act provides authority for the control of harmful or toxic substances at any stage of the life-cycle of these substances, including development, manufacturing, storage, transportation, use and disposal. The Act specifies that the Minister of the Environment may develop environmental objectives (ambient standards), release guidelines (emission standards) and codes of practice, as well as enforceable regulations based on these and other environmental standards. Regulations include standards for the storage and disposal of polychlorinated biphenyls (PCBs).

The Transportation of Dangerous Goods Act authorizes the creation and enforcement of safety standards for transport, preparation for transport, and the related handling of dangerous goods (including PCBs and radioactive substances).

The Pest Control Products Act authorizes the development and enforcement of safety standards for the storage, handling and use of pesticides.

3.3 Intergovernmental Air Pollution Agreements

Canada is a signatory to three international protocols of the United Nations Economic Commission for Europe (ECE), under the 1979 Convention on Long-Range Transboundary Air Pollution. The sulphur protocol (1985) commits signatories to reduce national sulphur dioxide emissions by 30 per cent of 1980 levels by 1993. The nitrogen oxides protocol (1988) commits signatories to freeze national nitrogen oxides emissions at 1987 levels by 1994. The protocol on volatile organic compounds (VOCs) (1991) commits signatories to freeze national VOC emissions at 1988 levels by 1999, and, for high ozone regions, to reduce VOC emissions by 30 per cent of 1988 levels by 1999.

The protocol for the reduction of sulphur dioxide emissions has been implemented in Canada by individual agreements between the Government of Canada and the seven easterly provinces, to reduce emissions of sulphur dioxide by approximately 40 per cent of actual 1980 emissions by 1994. Consistent with the international protocol on NOx and VOCs, and with the Canadian goal of reducing ozone levels to the ambient air quality objective of 82 parts per billion, the Canadian Council of Ministers of the Environment (CCME) has developed a comprehensive plan of action for the further management of nitrogen oxides and volatile organic compound emissions in Canada.

On March 13, 1991, the governments of Canada and the United States signed an agreement on air quality (the Air Quality Accord). Among other things, Canada agreed to:

- Cap SO_2 emissions in the 7 easternmost provinces at 2.3 million tonnes per year from 1995 to 1999.
- Achieve a permanent national cap of 3.2 million tonnes per year by 2000.
- Reduce annual emissions of NO_x from stationary sources by 100 000 tonnes per year below the year 2000 forecast level of 970 000 tonnes per year.
- Develop, by January 1, 1995, further annual national emission reduction requirements from stationary sources to be achieved by 2000 and/or 2005.
- By January 1, 1995, estimate SO_2 and NO_x emissions from each new existing electric utility unit greater than 25 MW, using a method of comparable effectiveness to continuous emission monitoring.
- Assess, notify and mitigate against significant possible transboundary air pollution impacts arising from new projects.

Federal/provincial agreements were renegotiated in 1993 to put the first of the above points into effect.

3.4 General Environmental Standards for Nuclear Power Generation: Atomic Energy Control Board

See Chapter 3 for a general discussion of the regulatory function of the Atomic Energy Control Board (AECB).

The AECB's standards for licensing and monitoring nuclear facilities include regulations pursuant to the Atomic Energy Control Act for limiting radiation dosage to the public, and transportation standards for packaging and marking nuclear substances. The Board receives advice on environmental standards from Environment Canada and frequently conducts its licensing activities under a joint regulatory process involving federal and provincial environment authorities. The AECB coordinates its regulatory activities with the federal Environmental Assessment and Review Process (EARP) and any provincial environmental review process that may be required for nuclear facilities.

3.5 General Environmental Standards for Electricity Generation and Transmission for Export: National Energy Board

See Chapter 3 for details of the National Energy Board's regulatory process.

Applicants for a permit for an export of electricity or for an international transmission line are required to submit information to the National Energy Board on the potential environmental impacts of the export of the line. The Board will apply the procedures specified in the federal EARP Guidelines Order in determining whether to recommend designating an application for the licensing or certification process. When a licence hearing is necessary, applicants may be required to undertake a detailed analysis of the project, including among other things, environ-mental considerations.

3.6 Federal Environmental Assessment and Review Process Guidelines Order

See Chapter 4 for details of the federal EARP.

The Guidelines Order sets out standard procedures that should be followed by federal government departments in conducting an initial screening of projects under their authority for significant environmental effects.

Prices Paid by Major Electric Utilities for Independent Power Production in 1994

Major Electric Utility	Purchase Rates	Pricing Formula	Remarks
Newfoundland and Labrador Hydro	Isolated Areas: depends on system	Based upon "share the savings" principle up to a maximum of 90% of the avoided fuel cost.	Purchases for isolated areas are evaluated based on the size of the system under consideration.
	Interconnected Areas: Not available. There are no current requirements for additional generation, however, proposals based on NLH's short run marginal costs will be entertained.	Based upon avoided cost with adjustments for reliability and seasonal availability.	Any future requests for proposals will be based upon competitive bidding.
Newfoundland Light and Power Co. Ltd.	Negotiable.	Negotiation up to the system incremental cost of generation (total avoided cost).	IPPs will be considered if they are identified as part of an integrated resource plan for the island. Energy from IPPs will be purchased anytime the negotiated price is less than the short-run marginal cost of production (i.e., fuel and variable O&M).
Maritime Electric	3.5¢/kWh (in 1994)	Average avoided cost of economy energy purchases from New Brunswick Power.	
Nova Scotia Power	Energy: 3.0¢/kWh	Full avoided cost based on system simulations.	Present forecast shows that NSP does not require additional capacity until sometime beyond 2000. Any new purchases up to this time would receive payments based on avoided energy cost.
NB Power	Non-Dedicated Energy: Rate varies monthly.	Avoided energy costs only.	90% of system decrement.
	Dedicated Capacity: on-peak: 5.45¢/kWh off-peak: 3.83¢/kWh	Avoided full cost.	Dedicated capacity is available to new NUG only after RFP process. Need is not projected until after 2000. Capacity up to 5 MW.

Prices Paid by Major Electric Utilities for Independent Power Production in 1994 (continued)

Major Electric Utility	Purchase Rates	Pricing Formula	Remarks
	Capacity: $20.34/kW/mo Energy: 3.2¢/kWh	Avoided full cost but tied to Belledune actual fuel and O&M costs.	Capacity greater than 5 MW
Hydro-Québec	4.9¢/kWh (1995 $)	Avoided cost.	The price is for high tension (greater than 15 MW). Capacity factor for 60% to 100%.
	5.2¢/kWh (1995 $)	Avoided cost.	The price is for an average tension (less than or equal to 15 MW). Capacity factor for 60% to 100%.
	3.98¢/kWh (summer 1995) 7.30¢/kWh (winter 1995)	Avoided cost	From renewable sources, 20 years contract, capacity less than or equal to 15 MW.
	4.73¢/kWh (in 1995)	Avoided cost	From renewable sources, capacity less than 10 MW. Capacity factor for 60% to 100%.
Ontario Hydro	Projects up to 5 MW:		
	Option 1 - Basic purchase rate schedule offered to non-utility generators regardless of the fuel or technology used.	Avoided cost.	To qualify for Option 1, a non-utility generator would have to enter into a contract with Ontario Hydro for a typical term of 20 years.
	Winter peak: 6.90¢/kWh	Peak rates are based on Ontario Hydro's 20-year incremental capacity and energy costs.	All time-differentiated rates adjusted annually at Ontario's CPI.
	Winter off-peak: 2.84¢/kWh	Off-peak rates are based on incremental energy cost.	Capacity factor is not a criterion in setting the rates.
	Summer peak: 6.21¢/kWh Summer off-peak: 1.81¢/kWh		
	Option 2 - Premium rates to projects that use renewable resources or use high efficiency energy conversion technology.	In principle, the pricing formula is the same as Option 1 above.	
	Winter peak: 7.29¢/kWh Winter off-peak: 3.01¢/kWh Summer peak: 6.56¢/kWh Summer off-peak: 1.92¢/kWh		

Prices Paid by Major Electric Utilities for Independent Power Production in 1994 (continued)

Major Electric Utility	Purchase Rates	Pricing Formula	Remarks
	Projects delivering over 5 MW net.	Negotiated	To be reviewed project-by-project.
Manitoba Hydro	< 3.0¢/kWh (1995)	Avoided cost.	Additional capacity will not be needed prior to 2011.
SaskPower	Rates established by competitive bidding.	Avoided cost.	25 MW NUG demonstration project planned for 1995 has been postponed. Additional capacity will not be needed until about the turn of the century.
TransAlta Utilities Alberta Power Edmonton Power and the City of Medicine Hat	5.2¢/kWh (fixed from 1990 to 1994) increasing to 6.0¢/kWh (fixed from 1995 to 1999) or 4.64¢/kWh starting in 1990, escalating with inflation.	Legislated rates.	These rates are applied to small power producers using renewable resources such as wind, hydro and biomass. Projects are up to 2.5 MW. A limited number of pilot projects in excess of 2.5 MW may be approved.
	1.2¢/kWh	Negitiated amount for energy at a cost less than avoided energy cost.	For various excess energy agreements.
	Other projects and energy from non-traditional sources such as generators powered by flare gas or co-generators.	To be negotiated.	
B.C. Hydro	Not available.		
Yukon Energy Corporation		Avoided cost.	Interim policy.
Northwest Territories Power	About 20¢/kWh.	Avoided cost.	Used in trial windpower projects

* CPI = Consumer Price Index
** IPP = Independent Power Producer

Source: Major electric utilities, March 1995

Definitions and Abbreviations

Alternating Current (AC):
A current that flows alternately in one direction and then in the reverse direction. In North America the standard for alternating current is 60 complete cycles each second. Such electricity is said to have a frequency of 60 hertz. Alternating current is used universally in power systems because it can be transmitted and distributed much more economically than direct current.

Base Load:
The minimum continuous load over a given period of time.

British Thermal Unit (BTu):
A unit of heat. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Capacity:
In the electric power industry, capacity has two meanings:

1. System Capacity: The maximum power capability of a system. For example, a utility system might have a rated capacity of 5000 megawatts, or might sell 50 megawatts of capacity (i.e., of power).

2. Equipment Capacity: The maximum power capability of a piece of equipment. For example, a generating unit might have a rated capacity of 50 megawatts.

Capacity Factor:
For any equipment, the ratio of the average load during some time period to the rated capacity.

Cogeneration:
A cogenerating system produces electricity and heat in tandem. Such systems have great potential in industry, where a significant requirement for electricity is coupled with a large demand for process steam.

Consumer Price Index (CPI):
A measure of the percentage change over time in the cost of purchasing a constant "basket" of goods and services. The basket consists of items for which there are continually measurable market prices, so that changes in the cost of the basket are due only to price movements.

Consumption:
Use of electrical energy, typically measured in kilowatt hours.

Conventional Generation:
Electricity that is produced at a generating station where the prime movers are driven by gases or steam produced by burning fossil fuels.

Current:
The flow of electricity in a conductor. Current is measured in amperes.

Demand Charge:
The component of a two-part price for electricity that is based on a customer's highest power demand reached in a specified period, usually a month, regardless of the quantity of energy used (e.g., $2.00 per kilowatt per month). The other component of the two-part price is the energy charge.

Direct Current (DC):
Current that flows continuously in the same direction (as opposed to alternating current). The current supplied from a battery is direct current.

Economy Energy:
Energy sold by one power system to another, to effect a saving in the cost of generation when the receiving party has adequate capacity to supply the loads from its own system.

Electrical Energy:
The quantity of electricity delivered over a period of time. The commonly used unit of electrical energy is the kilowatt-hour (kWh).

Electrical Power:
The rate of delivery of electrical energy and the most frequently used measure of capacity. The basic unit is the kilowatt (kW).

Energy Charge:
The component of a two-part price for electricity which is based on the amount of energy taken (e.g., 20 mills per kWh). The other component of the price is the demand charge.

Energy Source:
The primary source that provides the power that is converted to electricity. Energy sources include coal, petroleum and petroleum products, gas, water, uranium, wind, sunlight, geothermal, and other sources.

Firm Energy or Power:
Electrical energy or power intended to be available at all times during the period of the agreement for its sale.

Frequency:
The number of cycles through which an alternating current passes in a second. The North American standard is 60 cycles per second, known as 60 hertz.

Gigawatt (GW): One billion watts. (See Watt.)

Gigawatt hour (GW.h):
A unit of bulk energy. A million kilowatt hours. A billion watt hours.

Grid:
A network of electric power lines and connections.

Gross Domestic Product (GDP):
The total value of goods and services produced in Canada. GDP measured in constant dollars is defined as Real GDP.

Gross National Product (GNP):
The total value of production of goods and services measured at market prices.

Hertz (Hz):
The unit of frequency for alternating current. Formerly called cycles per second. The standard frequency for power supply in North America is 60 Hz.

Installed Capacity:
The capacity measured at the output terminals of all the generating units in a station, without deducting station service requirements.

Interruptible Energy or Power:
Energy or power made available under an agreement that permits curtailment or interruption of delivery at the option of the supplier.

Joule:
The international unit of energy. The energy produced by a power of one watt flowing for one second. The joule is a very small unit: there are 3.6 million joules in a kilowatt hour.

Kilovolt (kV): 1000 volts.

Kilowatt (kW):
The commercial unit of electric power; 1000 watts. A kilowatt can best be visualized as the total amount of power needed to light ten 100-watt light bulbs.

Kilowatt hour (kWh):
The commercial unit of electric energy; 1000 watt hours. A kilowatt hour can best be visualized as the amount of electricity consumed by ten 100-watt light bulbs burning for an hour. One kilowatt hour is equal to 3.6 million joules.

Load:
The amount of electric power or energy consumed by a particular customer or group of customers.

Load Factor:
The ratio of the average load during a designated period to the peak or maximum load in that same period. (Usually expressed in per cent.)

Megawatt (MW):
A unit of bulk power; 1000 kilowatts.

Megawatt hour (MW.h):
A unit of bulk energy; 1000 kilowatt hours.

Mill: 1/1000 of a dollar.

Net Exports:
Total exports minus total imports.

Nuclear Power:
Power generated at a station where the steam to drive the turbines is produced by an atomic process, rather than by burning a combustible fuel such as coal, oil or gas.

Peak Demand:
The maximum power demand registered by a customer or a group of customers or a system in a stated period of time such as a month or a year. The value may be the maximum instantaneous load or more, usually the average load over a designated interval of time, such as one hour, and is normally stated in kilowatts or megawatts.

Power System:
All the interconnected facilities of an electrical utility. A power system includes all the generation, transmission, distribution, transformation, and protective components necessary to provide service to the customers.

Primary Energy Consumption:
The amount of energy available to the final consumer, plus conversion losses and energy used by the energy supply industries themselves. (Conversion losses are losses in the processing of refined petroleum products, for example, or losses due to thermal and mechanical inefficiencies resulting from the conversion of fossil fuels - coal, oil and natural gas - into electricity in thermal power generation).

Reserve Generating Capacity:
The extra generating capacity required on any power system over and above the expected peak load. Such a reserve is required mainly for two reasons: (i) in case of an unexpected breakdown of generating equipment; (ii) in case the actual peak load is higher than forecast.

Secondary Energy Consumption:
The amount of energy available to, and used by, the consumer in its final form.

Terawatt Hours (TW.h):
One billion kilowatt hours.

Voltage:

The electrical force or potential that causes a current to flow in a circuit (just as pressure causes water to flow in a pipe). Voltage is measured in volts (V) or kilovolts (kV). 1 kV = 1000 V.

Watt:
The scientific unit of electric power; a rate of doing work at the rate of one joule per second. A typical light bulb is rated 25, 40, 60 or 100 watts, meaning that it consumes that amount of power when illuminated. A horse power is 746 watts.

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